B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

2007 Supplemental Wholesale Power Rate Case Initial Proposal

DIRECT TESTIMONY

Book 2
(FY 2009)

February 2008

BPA Exhibit No.	**Witness**
WP-07-E-BPA-63	Lefler, Bliven, Forman
WP-07-E-BPA-64	Misley, Hirsch, Booth, Schiewe, Van Orden
WP-07-E-BPA-65	Homenick, Lennox
WP-07-E-BPA-66	Petty, Anderson, Conger
WP-07-E-BPA-67	Russell, Normandeau, Conger, Lovell, Marks, Wagner
WP-07-E-BPA-68	Keep, Doubleday, Bliven, Brodie, Mace
WP-07-E-BPA-69	Fisher, Bolden, Doubleday, Gustafson, Keep, Ingram
WP-07-E-BPA-70	Brodie, Bliven, Doubleday, Homenick, Keep
WP-07-E-BPA-71	McHugh, Russell, Young
WP-07-E-BPA-72	Wedlund, Hirsch, Klippstein, Wagner
WP-07-E-BPA-73	Normandeau, Lovell, Wagner
WP-07-E-BPA-74	Lee, Homenick, Keep, Johnson
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POWER ADMINISTRATION

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WP-07-E-BPA-65	Supplemental Revenue Requirement Study	Ronald Homenick, Alexander Lennox
WP-07-E-BPA-66	Supplemental Market Price Forecast	Rob W. Anderson, Sid Conger, Jr., Robert J. Petty
WP-07-E-BPA-67	Supplemental Risk Analysis	Sid Conger, Jr., Byrne E. Lovell, Kenneth J. Marks, Michael R. Normandeau, Randy B. Russell, Arnold L. Wagner
WP-07-E-BPA-68	FY 2009 Section 7(b)(2) Rate Test Study	Raymond D. Bliven, Paul A. Brodie, William J. Doubleday, Byron G. Keep
WP-07-E-BPA-69	Supplemental Rate Design	Gery Bolden, William J. Doubleday, Daniel H. Fisher, Greg C. Gustafson, Allan E. Ingram, Byron G. Keep
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TESTIMONY of

VALERIE A. LEFLER, RAYMOND D. BLIVEN, and CHARLES W. FORMAN

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TESTIMONY of

VALERIE A. LEFLER, RAYMOND D. BLIVEN, and CHARLES W. FORMAN

Witnesses for the Bonneville Power Administration

SUBJECT: REOPENING OF THE WP-07 RATE PROCEEDING

Section 1: Introduction and Purpose of Testimony

Q. *Please state your names and qualifications.*

A. My name is Valerie A. Lefler and my qualifications are contained in WP-07-Q-BPA-29.

A. My name is Raymond D. Bliven and my qualifications are contained in WP-07-Q-BPA-58.

A. My name is Charles W. Forman and my qualifications are contained in WP-07-Q-BPA-61.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to describe BPA's policy guidance for reopening the WP-07 rate proceeding in response to rulings from the United States Court of Appeals for the Ninth Circuit (Ninth Circuit or Court) regarding: (1) BPA's 2000 Residential Exchange Program Settlement Agreements (REP Settlement Agreements); (2) the allocation of REP Settlement Agreement costs to BPA's FY 2002-2006 power rates; and (3) the incorporation of fish and wildlife costs in BPA's FY 2002-2006 power rates. This testimony provides the context and background to BPA's objectives in resetting FY 2009 rates and explains BPA's approach to revising information presented in the WP-07 Final Proposal for the purposes of this WP-07 Supplemental Rate Proceeding (Supplemental Proceeding).

Q. How is your testimony organized?

A. After this introduction, Section 2 discusses the principal reasons BPA is reopening the WP-07 rate proceeding. Section 3 describes BPA's general policy guidance for the

Supplemental Proceeding. Section 4 describes BPA's policy guidance for the Supplemental Proceeding regarding assumptions in the revenue requirement, including fish and wildlife program levels.

Section 2: Reopening the WP-07 Rate Proceeding

Q. Please describe the Court opinions BPA is responding to in this Supplemental Proceeding.

A. This Supplemental Proceeding is responding to the following opinions: *Portland General Elec. Co. v. Bonneville Power Admin.*, 501 F.3d 1009 (9th Cir. 2007) (*PGE*), *Golden NW Aluminum, Inc. v. Bonneville Power Admin.*, 501 F.3d 1037 (9th Cir. 2007) (*Golden NW*), and *Public Utility Dist. No. 1 of Snohomish County, Wash. v. Bonneville Power Admin.*, 506 F.3d 1145 (9th Cir. 2007) (*Snohomish*). In *PGE* the Court held that BPA's REP Settlement Agreements were contrary to the Northwest Power Act. In *Golden NW* the Court found that BPA had improperly allocated the costs of the REP Settlement Agreements to preference customers and also determined that the rates were not supported by substantial evidence because of inadequacies in addressing fish and wildlife costs. The Court remanded the WP-02 rates (FY 2002-2006) to BPA. In *Snohomish* the Court excised the "reduction of risk" discount from the Load Reduction Agreements (LRAs), ruling that this provision was actually founded on the original REP Settlement Agreements. The Court remanded the validity of the Reduction of Risk Discount, characterized by BPA's consumer-owned utilities (COU) as a "litigation penalty," to BPA for review.

Q. Why is BPA reopening the WP-07 rate proceeding?

A. BPA is reopening the WP-07 rate proceeding in order to respond to the three rulings cited above. BPA proposes to address these rulings in several ways, including resetting power rates for fiscal year (FY) 2009. Most of the issues discussed by the Court deal with the

REP and are addressed in Bliven, *et al.*, WP-07-E-BPA-52. The current testimony addresses the effects of the Court's rulings on BPA's rates for FY 2009. BPA's FY 2009 rates implement the proposed decisions discussed in Bliven, *et al.*, WP-07-E-BPA-52, and propose returning amounts owed to preference customers in response to the Court's rulings.

Q. *If the Court remanded BPA's WP-02 rates, why is BPA reopening the WP-07 rate proceeding?*

A. When developing the WP-02 rates, BPA allocated the costs of the REP Settlement Agreements to preference customers after application of the section 7(b)(2) rate test. As noted above, the Court found this allocation contrary to the Northwest Power Act. The WP-07 rates are being addressed in this Supplemental Proceeding because the WP-07 Final Proposal was based on the 2004 Amendments to the 2000 REP Settlement Agreements and the WP-07 rates continued the improper allocation of REP settlement costs.

Q. *Does BPA propose to address any other issues from the* Golden NW *ruling?*

A. Yes. In addition to the cost allocation issue noted above, the Court in *Golden NW* also ruled that BPA's fish and wildlife cost estimates developed for the WP-02 rates, and by extension the rates set pursuant to those estimates, were not supported by substantial evidence. The Court indicated BPA had relied on outdated assumptions and had not appropriately considered information presented to it regarding its fish and wildlife costs. In this testimony we explain how BPA proposes to address the Court's ruling with regard to fish and wildlife costs included in this Supplemental Proposal. *See also* Homenick and Lennox, WP-07-E-BPA-65.

Q. What issues will this Supplemental Proceeding address?

A. This Supplemental Proceeding will address the following issues:

- The remand of BPA's 2002 power rates in *Golden NW*. *See* Bliven, *et al.*, WP-07-E-BPA-52.
- The disposition of overpayments made to investor-owned utilities (IOU) for FY 2002-2006 under the REP Settlement Agreements addressed in the *PGE* opinion. *Id.*
- The disposition of payments made to Puget Sound Energy and PacifiCorp under the 2001 Load Reduction Agreements. *Id.*
- The disposition of the alleged "litigation penalty" payments addressed in the *Snohomish* opinion. *Id.*
- Proposed modifications to BPA's 1984 Section 7(b)(2) Implementation Methodology (Implementation Methodology). *See* Keep, *et al.*, WP-07-E-BPA-68.
- Proposed modifications to BPA's 1984 Section 7(b)(2) Legal Interpretation (Legal Interpretation). The Legal Interpretation will be addressed by parties in this Supplemental Proceeding through legal briefs and responded to by BPA in the Draft and Final Records of Decision. BPA's proposed changes to the Legal Interpretation are included in the Supplemental Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment A.
- The implementation of a revised Average System Cost Methodology as it relates to BPA's Supplemental Proposal. *See* McHugh, *et al.*, WP-07-E-BPA-71.
- The establishment of new power rates for FY 2009 based on the foregoing, as well as appropriate updates to costs and revenues for FY 2009.

Q. *Does BPA propose to continue to rely on the same financial and policy objectives established in the Financial Strategy and Risk Tolerance testimony from the WP-07 proceeding?*

A. Yes. BPA is continuing to rely on the same financial and policy objectives as established at the outset of the WP-07 rate proceeding. *See* Leathley, *et al.*, WP-07-E-BPA-08; *see also* Risk Analysis Study, WP-07-FS-BPA-04. However, because BPA is developing one-year rates for FY 2009, the Treasury Payment Probability (TPP) standard is 97.5 percent, the one-year equivalent of the two-year TPP standard of 95 percent. *See* Supplemental Risk Analysis Study, WP-07-E-BPA-48; *see also* Normandeau, *et al.*, WP-07-E-BPA-73. Although the same policies and objectives that existed prior to the WP-07 proceeding are still in effect, BPA is not relying on the portion of the Subscription Policy that supported the signing of the REP Settlement Agreements. Instead, as described in Bliven, *et al.*, WP-07-E-BPA-52, and Marks, *et al.*, WP-07-E-BPA-62, REP benefits are being recalculated as if the REP had been in effect during FY 2002-2008.

Section 3: Policy Guidance for BPA's WP-07 Supplemental Proceeding

Q. *What is BPA's general approach to this Supplemental Proceeding with respect to revising information used in the WP-07 Final Proposal?*

A. In addition to the REP changes necessitated by the Court's rulings, BPA's general approach to this Supplemental Proceeding is to address only those updates or changes from the WP-07 Final Proposal that are necessary or appropriate. A change is deemed necessary or appropriate if it can be substantiated by evidence or logic and if the change is significant to the rate being calculated. In other words, BPA is focusing on those components of the rate calculations that are necessary or appropriate to address in light of the Court's opinions or made necessary by events since the WP-07 Final Proposal was filed in July, 2006.

Q. *Does BPA propose to follow the "Partial Resolution of Issues" as included in its WP-07 Final Proposal?*

A. With the exception of Item 1, concerning the section 7(b)(2) rate test, BPA proposes to follow the "Partial Resolution of Issues" to the maximum extent practicable. *See* Supplemental Wholesale Power Rate Design Study (WPRDS), WP-07-E-BPA-49, Attachment A.

Q. *Why does BPA propose to treat Item 1 differently?*

A. Item 1 refers to two issues regarding the section 7(b)(2) rate test that directly affect the REP. *Id.* Due to the Court's rulings on the REP Settlement Agreements and BPA's WP-02 rate development, issues regarding the rate test and the implementation of the REP in the absence of the REP settlements are being addressed in this Supplemental Proceeding. *See* Bliven, *et al.*, WP-07-E-BPA-52.

Q. *What components of BPA's WP-07 FY 2009 power rates does BPA propose to update in this Supplemental Proceeding?*

A. BPA is proposing to change only those components of the WP-07 Final Proposal that require updates based on substantive evidence, logic or more current information. Loads and resources have been updated to reflect increased preference customer loads and resultant resource changes. For example, BPA has signed contracts with the City of Idaho Falls to purchase the output of the Idaho Falls bulb turbine, and with PPM Energy for part of the output of the Klondike III Wind Project. These resources are now included in BPA's available resources. These contracts were not previously included in BPA's WP-07 rate development because the contracts had not been signed at the time of the WP-07 Final Proposal. *See* Misley, *et al.*, WP-07-E-BPA-64.

BPA's revenue requirement has been updated for specific changes. *See* Homenick and Lennox, WP-07-E-BPA-65. BPA's market price forecast is not updated at this time, but updates are expected for the final Supplemental Proposal. *See* Petty, *et al.*, WP-07-E-BPA-66. BPA's Risk Analysis has been updated to incorporate new data from the various input sources. *See* Russell, *et al.*, WP-07-E-BPA-67. The Section 7(b)(2) Rate Test Study contains a number of revisions, and includes a proposed new Legal Interpretation and Implementation Methodology. *See* Supplemental Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachments A and B. A new forecast of Average System Costs (ASC) of utilities expected to participate in the REP is included. As explained in McHugh, *et al.*, WP-07-E-BPA-71, these forecasts will be replaced in the final Supplemental Proposal with ASCs determined through a separate and concurrent ASC review process. Risk Mitigation changes are limited to updated input data and financial conditions. *See* Normandeau, *et al.*, WP-07-E-BPA-73. Finally, all of the foregoing elements are brought together into the WPRDS to calculate new rates. *See* Brodie, *et al.*, WP-07-E-BPA-70.

Section 4: Policy Guidance for the Revenue Requirement, Including Fish and Wildlife Program Levels

Q. What portions of BPA's revenue requirement are being updated?

A. Updates have been made to a few specific program levels with known changes. For example, power purchase expense has been increased to reflect the Idaho Falls bulb turbine purchase. Depreciation and interest have been updated to reflect actual capital spending and financing activities through FY 2007. Operations and Maintenance expenses for the Columbia Generating Station (CGS) have also been updated to reflect a higher forecast. *See* Homenick and Lennox, WP-07-E-BPA-65, for all changes.

Q. *Why is BPA not proposing to update all program levels?*

A. BPA's program levels went through extensive internal and public review prior to and concurrent with the WP-07 rate case (see discussion of the Power Function Review process, below, and Revenue Requirement Study, WP-07-E-BPA-46, 23-26). Most forecasts included in the WP-07 Final Proposal are still reasonable forecasts for FY 2009 and do not warrant revision. Also, the decision was made to not modify the original schedule of Federal amortization established for FY 2007-2009 in the WP-07 Final Proposal.

Q. Why is BPA not modifying the schedule of Federal amortization for FY 2007-2009?

A. The final schedule of annual amortization payments for the rate period in the WP-07 Final Proposal was the result of an amortization shift, necessary to accommodate expected cash flows. Specifically, approximately $82 million of planned amortization in FY 2009 was shifted to FY 2007 and FY 2008, with no change to the total amortization for the rate period. Because the FY 2007 payment was made as scheduled, and current and future debt management plans, particularly related to Debt Optimization, have been constructed around the established schedule, the originally scheduled amortization for FY 2009 that was the result of the shift will be used in the development of the revenue requirement. *See* Homenick and Lennox, WP-07-E-BPA-65.

Q. Does BPA's WP-07 Final Proposal suffer the same infirmities identified by the Court in Golden NW with regard to forecasted fish and wildlife spending levels in BPA's WP-02 Final Proposal?

A. No. BPA's forecast of fish and wildlife program expense and capital spending for FY 2007-2009 was confirmed very close in time to the WP-07 Final Proposal, as were all other program levels. BPA was using the most up-to-date information possible, with intensive public review through the Power Function Review (PFR) processes.

Q. Please explain the PFR Process.

A. BPA held the PFR beginning in January 2005. The PFR was a series of technical, management, and public workshops designed to provide an opportunity for customers and constituents to examine, understand, and provide input on BPA's cost projections that formed the basis for BPA's WP-07 Initial Rate Proposal. *See* Revenue Requirement

Study, WP-07-FS-BPA-02, 12-16, and Appendix A for a complete description of the process.

Q. *How were fish and wildlife spending levels addressed?*

A. One PFR workshop was devoted solely to examining BPA's projected spending levels for the fish and wildlife program. In addition to and concurrent with the PFR, there were five separate public workshops held around the region to discuss in detail projected fish and wildlife program expenses and capital spending for the FY 2007-2009 rate period. Additionally, BPA participated in numerous meetings with the Northwest Power and Conservation Council (Council), States, Tribes, constituents and customers beginning in 2004 to receive input on the appropriate approach to forecast fish and wildlife program spending. The comments gathered in these forums were used to inform BPA's forecast of FY 2007-2009 spending levels included in the PFR. Those forecasts were incorporated into BPA's WP-07 Initial Proposal.

Q. *Were these forecasts reconsidered after BPA's WP-07 Initial Proposal?*

A. Yes. "PFR II" began after the publication of the WP-07 Initial Proposal. BPA held a series of public workshops in early 2006 focused on each of the major power expense categories that were reviewed previously in the first phase of the PFR, including fish and wildlife program levels. The PFR II final close-out report incorporated changes made during the process and was the basis for the program levels included in the WP-07 Final Proposal.

Q. *Were there other differences in how fish and wildlife program levels were treated in developing BPA's WP-07 rates compared with the development of BPA's WP-02 rates?*

A. Yes. BPA also treated uncertainty about future fish and wildlife costs differently in the WP-07 Final Proposal. Instead of establishing a range of alternative fish and wildlife costs as BPA had done in developing its WP-02 rates, BPA's WP-07 rate proposal included forecasts of program levels (as determined through the PFR process) in the revenue requirement. Then, in addition, BPA developed a variety of risk mitigation tools to address remaining uncertainty, including the National Marine Fisheries Federal Columbia River Power System Biological Opinion (NFB) Adjustment and the Emergency NFB Surcharge, to address the uncertain outcome of specific litigation over the FCRPS Biological Opinion (BiOp).

Q. *How does BPA's Supplemental Proposal respond to the* Golden NW *ruling regarding fish and wildlife costs?*

A. BPA will take steps to ensure that its assumptions about fish and wildlife spending levels are as up-to-date as possible for the final Supplemental Proposal, and will provide an opportunity outside this Supplemental Proceeding for fish and wildlife managers and others to review the information and provide feedback to BPA on the estimates of those fish and wildlife program levels. After considering all information and comments, BPA will incorporate final fish and wildlife program level estimates in the final Supplemental Proposal.

Q. *Please describe these steps in more detail.*

A. In this Supplemental Proposal, BPA's estimated expenditures for its fish and wildlife commitments for FY 2009 are consistent with the costs it previously forecast for the WP-07 rate period. However, BPA expects that during the course of this proceeding events may occur that could provide BPA with new information about its fish and wildlife costs. *See* Homenick and Lennox, WP-07-E-BPA-65. This could result in changes to the program levels reflected in BPA's Supplemental Proposal revenue requirement. *Id.* These events include the issuance by NMFS of a final FCRPS BiOp regarding the impacts of the FCRPS on salmon and steelhead listed under the Endangered Species Act (ESA) (expected to be issued in May 2008), as well as possible long-term agreements involving BPA and other regional sovereigns regarding related implementation actions to address ESA-listed species and other fish and wildlife species.

BPA expects to include the estimated costs of implementing the final FCRPS BiOp, and the costs of any associated long-term agreements, in the final Supplemental Proposal.

Q. Will parties have an opportunity to review and understand these forecasts prior to the final Supplemental Proposal?

A. Yes. BPA will hold a workshop outside of this proceeding but prior to the final Supplemental Proposal to provide an opportunity to any interested person or organization to review the program level changes from the WP-07 Final Proposal and from the initial Supplemental Proposal. This workshop will address the changes in program levels that are reflected in the Supplemental Proposal, as well as any subsequent changes that are necessary in the final Supplemental Proposal. It will provide interested parties an opportunity to review BPA's updated forecasts, including the forecast of fish and wildlife spending levels, and to provide any additional information they believe BPA may not have captured. BPA will take comment and then issue a close-out report following the workshop. BPA will reflect the results of this workshop in the FY 2009 revenue requirement in BPA's final Supplemental Proposal.

Q. Why isn't BPA estimating the changes in fish and wildlife program levels now, and including them in this Supplemental Proposal?

A. Estimates of fish and wildlife program levels and capital investments for this proceeding would be too preliminary to be useful at this point in rate development, because they are subject to change based on comments by participants in the FCRPS BiOp remand process or, in the case of the long-term agreements, because they are the subject of ongoing negotiations. It would be more prudent to provide BPA's estimates once the relevant proceedings are completed, if possible, or if not completed, then closer to completion, such that estimates in the final Supplemental Proposal will be as current as possible.

Q. What would be the effect on this Supplemental Proposal of a subsequent court ruling from Judge Redden that ordered actions different from the revised Biological Opinion?

A. If Judge Redden issues an order that requires actions different from the final Biological Opinion, and the order is issued in time to incorporate its effects into the final Supplemental Proposal, BPA will do so. If such an order is issued after the latest opportunity to incorporate it into the final Supplemental Proposal, the order would likely meet the definition of an NFB Trigger Event. If BPA is in a cash crunch at the time, BPA will implement either the NFB Adjustment procedures, or the Emergency NFB Surcharge procedures. *See* Normandeau, *et al*., WP-07-E-BPA-73.

Q. Are there other possible fish and wildlife program level and capital investment changes that could be included in the final Supplemental Proposal?

A. Yes. BPA is aware of additional areas of potential costs, including ongoing litigation regarding the ESA and the Willamette Valley FCRPS Projects and ESA litigation specific to the Libby Project. BPA will identify other potential program level and capital investment changes as appropriate and, if there is a likelihood of additional costs in FY 2009, BPA will provide the best forecast of those costs in the public process external to this rate case, allow discussion and input in that process, and incorporate the results of that public process in the final Supplemental Proposal.

There is also the potential for BPA's fish and wildlife program levels to change as a result of amendments to the Council's Fish and Wildlife Program. Because those amendments are not due to be implemented until early in 2009, however, BPA does not expect to make changes to its funding commitments in relation to any Program amendments until FY 2010 (starting in October of 2009) at the earliest. As a result, BPA does not expect to propose changes to its fish and wildlife costs forecasts in response to Council Program amendments in this Supplemental Proposal

Q. *What is the appropriate forum for fish and wildlife agencies, or others, to express their agreement or disagreement with BPA's forecast of fish and wildlife program levels?*

A. As noted above, fish and wildlife agencies, and others, will be able to review and comment on BPA's fish and wildlife program level forecasts in a separate process concurrent with this Supplemental Proceeding. BPA will consider all relevant information, particularly to the extent the fish and wildlife managers, or others, identify new information or changed circumstances that BPA has not considered in developing its fish and wildlife cost forecasts. Where there are disagreements, BPA will seek to resolve them and reflect any resolution in the final product. BPA notes, however, that the Supplemental Proceeding and the external process for updating fish and wildlife program level forecasts are not the forums where BPA makes decisions about its fish and wildlife *obligations*. Requests for increased or decreased spending for BPA's fish and wildlife obligations should be made to BPA in the course of the relevant processes and forums.

Q. *What are the relevant processes and forums?*

A. BPA determines what it will spend for fish and wildlife in a variety of forums and processes external to BPA's rate cases. For example, BPA establishes its commitments for fish and wildlife spending for the Northwest Power and Conservation Council's Fish and Wildlife Program following a process under the Northwest Power Act. For the FY 2007-2009 rate period, BPA made and published its project decisions in early 2007, and posted them on its website. The remand of the 2004 FCRPS Biological Opinion is another example of a proceeding external to the rate case in which BPA determines its fish and wildlife costs.

Q. *Is BPA deciding any fish and wildlife costs in this Supplemental Proceeding?*

A. No. The Supplemental Proceeding is not the forum in which BPA determines what it will spend on its fish and wildlife obligations. The Supplemental Proceeding is the forum in which BPA identifies its expected program levels and capital investments for the rate period and establishes rates to recover those costs.

Q. What will happen if expected fish and wildlife program levels and capital investments included in the Supplemental Proposal are incorrect?

A. Fish and wildlife costs are no different than any other cost BPA estimates in setting rates. BPA has established a number of risk mitigation tools to deal with cost uncertainties. These tools include cash reserves, the Cost Recovery Adjustment Clause (CRAC), and the Dividend Distribution Clause (DDC). In addition, BPA established the NFB Adjustment and the NFB Emergency Surcharge in the WP-07 Final Proposal to deal specifically with certain fish and wildlife cost risks.

Q. Is BPA proposing to change its risk mitigation tools?

A. BPA proposes to continue to strike a balance between lower base rates and adjustments to those base rates through a CRAC, NFB Adjustment, Emergency NFB Surcharge or a DDC. All of the risk mitigation tools contained in the WP-07 Final Proposal are proposed to continue in this Supplemental Proposal. Any proposed changes are because this Supplemental Proceeding establishes one-year rates rather than three-year rates. *See* Normandeau, *et al.*, WP-07-E-BPA-73.

Q. Does this conclude your testimony?

A. Yes.

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RICHARD VAN ORDEN, and ROGER SCHIEWE

Witnesses for Bonneville Power Administration

SUBJECT: SUPPLEMENTAL LOAD RESOURCE STUDY

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Jon A. Hirsch and my qualifications are contained in WP-07-Q-BPA-16.

A. My name is Timothy C. Misley and my qualifications are contained in WP-07-Q-BPA-41.

A. My name is Glen S. Booth and my qualifications are contained in WP-07-Q-BPA-59.

A. My name is Richard Van Orden and my qualifications are contained in WP-07-Q-BPA-67.

A. My name is Roger Schiewe and my qualifications are contained in WP-07-Q-BPA-48.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to describe methods and updates to the 2007 Wholesale Power Rate Case Initial Proposal, Load Resources Study, WP-07-E-BPA-01. Additionally this testimony sponsors the 2007 Supplemental Wholesale Power Rate Case Initial Proposal, Load Resource Study (Study), WP-07-E-BPA-45, and the 2007 Supplemental Wholesale Power Rate Case Initial Proposal, Load Resource Study Documentation (Documentation), WP-07-E-BPA-45A.

Q. How is your testimony organized?

A. The Load Resource testimony contains 10 sections, including this one. Section 2 discusses the updates to the total retail load forecasts for the public body and cooperative utilities and Federal agencies (together referred to as “Public Agencies”) served by BPA.

Section 3 describes the results of the updates to those forecasts. Section 4 indicates that there were no changes to the IOU and DSI firm requirements power sales contract (PSC) obligation forecasts. Section 5 describes BPA's Load Resource Study process. Section 6 describes BPA's hydro regulation studies. Section 7 describes BPA's Federal generating resources. Section 8 addresses BPA's treatment of Federal system contracts. Section 9 describes BPA's treatment of Federal system transmission losses. Section 10 addresses Pacific Northwest (PNW) regional total hydro resources used in the Market Price Forecast Study, WP-07-E-BPA-47.

Section 2. Public Agencies Total Retail Load Forecasts

Q. Please describe the updates to the Public Agency total retail load forecasts.

A. BPA produces, or obtains from its customers, total retail load forecasts, which are used in BPA processes such as ratemaking. A description of the process or method BPA uses to produce the Public Agency total retail load forecasts is contained in the Study, WP-07-E-BPA-45, Section 2.2.2. For FY 2007-2008, this forecast was not updated from the 2007 Wholesale Power Rate Case Final Proposal (WP-07 Final Proposal). The Public Agency total retail load forecast for FY 2009 was updated from the WP-07 Final Proposal. This revision was needed because many of the utility-specific models were updated with current actual utility loads through fiscal year (FY) 2006, and the total retail load forecasts were re-estimated.

Section 3. Results from Updating Forecasts

Q. Please describe the results from updating the firm requirements PSC obligation forecasts.

A. Overall, updates for the FY 2009 forecasts caused an increase in BPA's firm requirements PSC obligation forecasts. Projected sales to BPA's load following customers increased approximately 150 aMW from the WP-07 Final Proposal. The Priority Firm (PF) Block amounts decreased approximately 56 aMW. Changes to the generation estimates of the Slice resource stack increased the Slice amount approximately 17 aMW. These changes are discussed in the Study, WP-07-E-BPA-45, Section 2.2.2.

Q. Has the growth rate of BPA's Public Agency firm requirements PSC obligation forecast changed?

A. Yes. BPA's total Public Agency firm requirements PSC obligations served at PF rates are projected to grow at an average annual rate of 1.4 percent per year for FY 2007-2009. Previously the projected annual average growth rate was 0.6 percent for the same period.

Q. Why has the growth rate changed?

A. BPA updated its customer firm requirements PSC obligation forecasts by incorporating FY 2006 actual data in the load forecast model as discussed in the Study, WP-07-E-BPA-045, Section 2.2.2. In addition, several customers' consumer-owned generation did not operate at the levels originally forecast. Therefore, the consumer-owned generation amounts were adjusted downward for FY 2009, and this adjustment was incorporated in the updated forecast.

BPA's firm requirements PSC obligation forecasts for FY 2009 changed in the following manner: (1) approximately 65 percent of the load following customers' firm requirements PSC obligation forecasts increased; (2) approximately 25 percent of the load following firm requirements PSC obligation forecasts decreased; and (3) approximately 10 percent of the load following firm requirements PSC obligation forecasts did not change. These changes increased BPA's load following firm requirements PSC obligation forecast for FY 2009 by approximately 150 aMW from the WP-07 Final Proposal. Since BPA's firm requirements PSC obligation forecast for FY 2007 and FY 2008 remained unchanged and FY 2009 increased, the average annual rate of growth over the FY 2007-2009 period increased by 0.8 percent from the WP-07 Final Proposal.

Q. Have BPA's actual power sales tracked well to forecasts of its firm requirements PSC obligations for BPA's Public Agency customers?

A. Yes. For FY 2004, the forecast firm requirements PSC obligations for the load following customers, including the pre-Subscription customers, exceeded the actual sales to those customers by 1.3 percent, or 42 aMW. For FY 2005, forecast firm requirements PSC obligations exceeded the actual BPA firm requirements PSC purchases by 0.8 percent, or 26 aMW. In FY 2006, actual BPA firm requirements PSC purchases exceeded forecast firm requirements PSC obligations by only 0.4 percent or 12 aMW. For FY 2007, forecast firm requirements PSC obligations exceeded the actual BPA firm requirements PSC purchases by 0.9 percent, or 31 aMW.

Section 4. IOU and DSI Firm Requirements PSC Obligation Forecasts

Q. Did the IOU and DSI firm requirements PSC obligation forecast change from the WP-07 Final Proposal?

A. No. The IOU and DSI firm requirements PSC obligation forecast did not change from the WP-07 Final Proposal.

Section 5. Load Resource Study Process

Q. How are the Federal system firm requirements PSC and other contract obligations treated in the Study?

A. The Study treats all Federal system firm requirements PSC and other contract obligations as firm obligations that are served regardless of weather, water, or economic conditions. For FY 2007-2008, BPA's firm requirements PSC obligations did not change from the WP-07 Final Proposal. However, this Study's firm requirements PSC obligations for

FY 2009 were changed to incorporate updates to BPA's firm requirements PSC obligations. These changes are further described in the Study, WP-07-E-BPA-45, Section 2.2, *Federal System Load Obligation Forecast.* The firm requirements PSC and other contract obligations of the Federal system are summarized monthly for energy in average megawatts, in the Documentation, WP-07-E-BPA-45A, Section 2.3, Tables 2.3.1 through 2.3.3, *Loads and Resources-Federal System, (2002 PSC Sales), (Slice Sales), (Exports)* and *(Intra-Regional Transfers (Out))*. These obligations are detailed monthly for energy in aMW, HLH MWh, and LLH MWh in the Documentation, WP-07-E-BPA-45A, Sections 2.4 through 2.6, Table A-2, *Exports*, Table A-16, *Intra-Regional Transfers*, and Table A-22, *BPA Power Sales Contracts*. These obligations are used as inputs to the Risk Analysis Study, WP-07-E-BPA-48.

Q. How are the Federal system resources and contract purchases treated in the Study?

A. The Study's hydro regulation analysis sets hydro project generating characteristics for the Federal system. The firm energy capability of Federal hydro resources is estimated using 1937 water conditions. This low flow water condition approximates one of the lowest water years of the 50-water years of record (August 1928 through July 1978) in the Columbia River Basin.

For FY 2008 and FY 2009, the hydro regulation generation estimates for this Study were not changed from the WP-07 Final Study. For FY 2009, this Study incorporates an update to the regulated hydro improvement forecast. Details of the Federal system regulated hydro analysis are presented in the Study, WP-07-E-BPA-45, Section 2.3.2.1, Regulated Hydro Generation Forecast. The energy, in average megawatts, of the Federal system regulated hydro under 1937 water conditions, is summarized in the Documentation, WP-07-E-BPA-45A, Section 2.3, Tables 2.3.1 through 2.3.3, Loads and Resources-Federal System, (Regulated Hydro). The hydro energy is detailed in the Documentation, WP-07-E-BPA-45A, Section 2.4, Table A-3, Federal Regulated Hydro Projects. The monthly output of the hydro system varies greatly, depending on the season and water year. The hydro regulation study provides 50-water year Federal hydro generation estimates for FY 2007-2009. This 50-water year data is used in the Risk Analysis Study, WP-07-E-BPA-48, and presented in the Risk Analysis Documentation, WP-07-E-BPA-48A, Tables 3 through 6.

The independent hydro projects generation estimates were not changed for FY 2007-2008. For FY 2009, independent hydro generation estimates were updated to include BPA's generation acquisition of the Idaho Falls Power bulb turbine projects. Details of the Federal system independent hydro analysis are presented in the Study, WP-07-E-BPA-45, Section 2.3.2.2, Independent Hydro Generation Forecast. The energy, in average megawatts, of the Federal system independent hydro under 1937 water conditions, is summarized in the Documentation, WP-07-E-BPA-45A, Section 2.3, Tables 2.3.1 through 2.3.3, Loads and Resources-Federal System, (Independent Hydro). The hydro energy is detailed in the Documentation, WP-07-E-BPA-45A, Section 2.4, Table A-4, Federal Independent Hydro Projects. This 50-water year data is used in the Risk Analysis Study, WP-07-E-BPA-48, and presented in the Risk Analysis Documentation, WP-07-E-BPA-48A, Tables 3 through 6.

The Study assumes that all Federal system non-hydro resources and contract purchases are firm resources available to meet Federal obligations, regardless of weather, water, or economic conditions. For FY 2009, this Study incorporates three new non-hydro resource or contract purchase estimates for the study period: (1) BPA's generation acquisition of 22.62 percent of the Klondike III wind project; (2) updates to the CGS maintenance schedule; and (3) BPA's purchase of the Slice Excess Requirements Energy (ERE). Details of BPA's non-hydro resources are presented in the Study, WP-07-E-BPA-45, Section 2.3.3, Other Federal System Generation Forecast and Section 2.3.4, Other Federal System Contract Purchases. The expected generation from non-hydro resources and contract purchases is summarized monthly for energy in average megawatts, in the Documentation, WP-07-E-BPA-45A, Section 2.3, Tables 2.3.1 through 2.3.3, Loads and Resources-Federal System, (Imports), (Renewables), (Large Thermal), (Non-Federal Canadian Entitlement Return for Canada), (Intra-Regional Transfers (In)), and (Non-Utility Generation). This data is detailed monthly for energy in aMW, HLH MWh and LLH MWh in the Documentation, WP-07-E-BPA-45A, Sections 2.4 through 2.6, Table A-5, Federal Imports, Table A-8, Federal Renewable Resources, Table A-10, Federal Large Thermal, Table A-15, Canadian Entitlement Return for Canada, Table A-16, Intra-Regional Transfers (In), and Table A-24, Federal Non-Utility Generating Resources by Project. This data is provided for the Risk Analysis Study, WP-07-E-BPA-48.

Section 6. Hydro Regulation Studies

Q. Were the hydro regulation studies updated for this Study to include new Biological Opinion (BiOp) operations?

A. No. The hydro regulation studies presented in this Study were not updated from the WP-07 Final Proposal. BPA plans to update known reservoir operating assumptions in the final Supplemental Proposal. This will include information from any agreed-upon operations for FY 2008 and information from the final Federal Columbia River Power System (FCRPS) BiOp for FY 2009. In the event that the final BiOp is not available, BPA will make its best estimate of operations under the final BiOp for use in the final WP-07 Supplemental Proposal.

Q. Did any aspect of the regulated hydro generation estimates in this Study not directly modeled in the hydro regulation studies change from the WP-07 Final Proposal?

A. For FY 2007-2008, there were no changes to the hydro improvement estimates from the WP-07 Final Proposal. However, for FY 2009, the hydro improvement estimates were updated from the WP-07 Final Proposal, increasing the Federal system regulated hydro generation estimates by approximately 40 aMW under 1937 critical water conditions. The hydro improvements are included in those projects' generation estimates.

Q. *Please describe the primary drivers of reservoir operations in the hydro regulation studies.*

A. The hydro regulation studies used in the Study were not updated from the WP-07 Final Proposal. These hydro regulation studies incorporated hydro plant operating requirements and project operating characteristics that are based on data submittals taken from the Pacific Northwest Coordination Agreement (PNCA). Operating requirements include, but are not limited to, storage content limits determined by rule curves, maximum project draft rates determined by each project, and flow and spill objectives determined by the National Oceanographic and Atmospheric Administration Fisheries (NOAA Fisheries) Biological Opinion (BiOp) published November 2004, and the United States Fish and Wildlife Service (USFWS) 2000 Biological Opinions for the Snake River and Columbia River projects.

Q. *Does this Study reflect the current method of reservoir operation in the PNCA planning process?*

A. No, this Study reflects the PNCA reservoir operations incorporated at the time of the WP-07 Final Proposal. Since the WP-07 Final Proposal, there have been PNCA updates to reservoir operations that BPA will most likely incorporate into the final WP-07 Supplemental Proposal.

Q. *Please describe the steps in the hydro regulation study.*

A. First, an Actual Energy Regulation (AER) study is run to determine the operation of the U.S. Federal hydro projects under each of the 50-historic water years while meeting the Firm Energy Load Carrying Capability (FELCC) produced by the PNCA final regulation. In this step, the Canadian reservoir operation is set by the assured operating plan (AOP) and updated for changes specified in the Detailed Operating Plan (DOP) for each year. The U.S Federal, U.S. non-Federal, and Canadian reservoirs draft to meet the Coordinated System FELCC, while continuing to meet individual reservoir non-power operating requirements. If possible, all projects draft to their Energy Content Curves (ECC) to produce secondary energy. The project operation from the AER study determines the drafting rights of each of the projects for use in the operational study.

Second, an operational 50-water year study is run using estimated regional firm loads developed for each year of the Study. The operation of the non-Federal projects is limited by the proportional draft points (PDP) developed in the 50-water year AER study.

These steps are further detailed in the Study, WP-07-E-BPA-45, Section 2.3.2, Federal System Hydro Generation.

Q. What are the major differences among the FY 2007, 2008, and 2009 hydro regulation studies?

A. There are two major differences in the hydro regulation studies for FY 2007, 2008, and 2009. First, there are yearly differences in the hydro regulation studies that are based on modeling assumptions regarding the BiOp implementation of spill for juvenile bypass operations during the April through August period. As Removable Spillway Weirs (RSW) are added at some of the projects at various times during the FY 2007-2009 rate period, the amounts of spill required for juvenile bypass are expected to change. These spill assumptions were not updated from the WP-07 Final Proposal; however, BPA expects to incorporate known reservoir operating assumptions for FY 2009 in the final WP-07 Supplemental Proposal.

Second, the amount of anticipated hydro generation increases because the implementation of hydro improvement programs varies with each year of the Study. These improvements are part of BPA's capital improvements programs. Hydro improvement estimates are project-specific and directly relate to the regulated hydro generation forecast produced by the hydro regulation simulation model, HYDSIM. Hydro improvements are calculated by multiplying a project's specific hydro improvement generation factor by that project's HYDSIM generation estimate. The estimated hydro improvement generation increase is not shown as a line item; rather it is included in that project's total hydro generation amount. For FY 2007-2008, the hydro improvement estimates were not updated from the WP-07 Final Proposal. The hydro improvement generation factors for FY 2009 were updated for this Study, thereby changing the regulated hydro generation estimates at specific regulated hydro projects. The hydro improvements estimates will change to reflect updated hydro regulation studies for the final WP-07 Supplemental Proposal.

Q. Please explain the difference between two modes of hydro regulation studies: refill and continuous.

A. There are two modes of hydro regulation studies: refill and continuous. Both are used to estimate the energy production of the hydro system. However, each mode is different in how it treats initial reservoir conditions. Continuous hydro regulation studies operate from one water year to another, using the previous water year's final reservoir elevations as the initial reservoir elevations for the following water year. Refill hydro regulation studies operate each water year independent of all other water years, using the same initial reservoir storage elevation for each water year. For ratemaking, continuous hydro regulation studies are typically used because there is little or no information on initial reservoir elevations such as when considering operations for a future year. For the FY 2007-2009 studies, each hydro regulation study was run in the continuous mode.

Q. In the Study, why is the hydro regulation study called a "50-water year study?"

A. The hydro system operation under current operating requirements is simulated over the 50-historic water conditions from August 1928 through July 1978 (operating year 1929 through 1978) using HYDSIM. HYDSIM produces a monthly estimate of hydro energy production that could reasonably be expected from the hydropower system over a wide range of runoff conditions. The Federal hydro generation estimates under 50-water conditions are used as inputs to the Risk Analysis Study, WP-07-E-BPA-48, which estimates revenues and risks associated with various load, resources, and rate scenarios. The Federal hydro generation estimates under 50-water conditions are presented in the Risk Analysis Documentation, Tables 4 through 6, WP-07-E-BPA-48A.

Q. Please explain why BPA uses a 50-water year hydro regulation study.

A. BPA uses the 50-water year hydro regulation study because it has been a historically prudent and reasonable measure to forecast the expected operations of the regulated hydro projects for varying hydro conditions. Approximately 80 percent of BPA's Federal system resource stack is comprised of hydro generation that can vary annually by up to 5,000 aMW. Depending on water conditions, annual Federal hydro generation estimates for FY 2009 range from 6,600 aMW to 11,250 aMW. BPA uses the HYDSIM regulation simulation model to estimate regulated hydro project generation for varying water conditions, which takes into account specific flows, volumes of water, elevations at dams, biological opinions, and many other aspects of the hydro system.

Additionally, BPA has generation estimates for other hydro projects that are based on 50-historic water years, 1929 through 1978. These projects are called "independent hydro" projects because their operations are not regulated in the HYDSIM model and they have much less storage capability than hydro projects in the Columbia River Basin. The independent hydro projects usually have generation estimates for each of the 50-water years. Most of the independent hydro projects are not Federally owned and their generation estimates must be updated with the cooperation of each project owner. For those independent hydro projects that did not have data for 50-water years, generation estimates for those projects were expanded using the project's median generation to estimate generation for the additional water years.

Section 7. Federal System Generating Resources

Q. What Federal System regulated hydro generation is included in the Study?

A. The generation forecast for the Federal system regulated hydro projects is set by the hydro regulation study using the HYDSIM hydro regulation model. HYDSIM produces month average energy production estimates by project incorporating 50-historic water years (1929 through 1978). The Federal system regulated hydro generation includes estimated generation increases due to capital improvements at specific Federal system projects. The Federal hydro resources are presented in fiscal year format to be consistent within this Study. The detailed monthly energy, in average megawatts, for each regulated hydro project is shown in the Documentation, WP-07-E-BPA-45A, Section 2.4, Table A-3, Federal Regulated Hydro Projects. The summarized HLH/LLH split of the regulated hydro generation estimates is presented in the Supplemental Risk Analysis Study, WP-07-E-BPA-48.

Q. What Federal independent hydro generation is included in the Study?

A. Monthly average energy production estimates for the Federal system independent hydro projects are set by the project owners for the 50-historic water years (1929 through 1978). The Federal independent hydro resources are presented in fiscal year format to be consistent within this Study.

For FY 2007-2008, the independent hydro generation estimates did not change from the WP-07 Final Proposal. For FY 2009, the independent hydro generation estimates for this Study were updated to include BPA's generation acquisition for the output of the Idaho Falls Power bulb turbine projects. BPA signed a contract for the output from these projects through September 30, 2011. For FY 2009, the inclusion of these projects increased Federal system independent hydro generation estimates approximately 18 aMW annually, under 1937 critical water conditions.

The detailed monthly energy, in average megawatts, for each independent hydro project is shown in the Documentation, WP-07-E-BPA-45A, Section 2.4, Table A-4, *Federal Independent Hydro Projects*. The summarized HLH/LLH split of the independent hydro generation forecast is presented in the Risk Analysis Study, WP-07-E-BPA-48.

Q. How are hydro generation improvements to the Federal system hydro resource generation treated in the Study?

A. The Study includes expected increases in hydro generation for specific Federal regulated hydro projects resulting from BPA's capital improvements programs. These improvements are expected to increase and preserve Federal hydro generation by: (1) replacing turbine runners to preserve and increase hydro generation and to make the turbine operation more fish friendly; (2) providing increased reliability by decreasing forced and planned outages; and (3) implementing hydro system optimization and operational planning tools to increase generation efficiency. These generation increases are not captured in the hydro regulation studies. The increased generation associated with these hydro improvements is calculated by multiplying a project's specific hydro improvement generation factor by that project's generation projection. The hydro improvement forecast varies by fiscal year and water year.

For FY 2007-2008, the hydro improvement estimates were not updated from the WP-07 Final Proposal. For FY 2009, the hydro improvement generation factors were updated for this Study, increasing Federal system hydro improvement estimates by approximately 40 aMW under 1937 critical water conditions from the WP-07 Final Proposal. BPA's hydro improvement estimates will be updated to reflect changes in the hydro regulation studies for the final WP-07 Supplemental Proposal.

Using 1937 water conditions, generation increases are expected to yield as much as 79 aMW in FY 2007, increasing to 140 aMW by FY 2009. *See* Documentation, WP-07-E-BPA-45A, Section 2.3, Table A-3, *Federal Regulated Hydro Projects*.

Q. What other Federal system generation besides regulated and independent hydro are included in the Study?

A. In addition to the generation from the Federal system regulated and independent hydro projects, this Study includes the output of several generation projects contracted for or assigned to BPA. These generation sources are called "other Federal system generation."

For FY 2007-2008, the other Federal system generation estimates did not change from the WP-07 Final Proposal. For FY 2009, the other Federal system generation projections were updated as follows: (1) BPA's Federal Renewable Resources now include the acquisition of 22.62 percent of the output of the Klondike III wind project through October 5, 2027, which increased total Federal system resources about 15 aMW in FY 2009; and (2) BPA's Large Thermal incorporates an update to the CGS maintenance schedule. This change increased the generation in some months and included a longer estimate of scheduled maintenance, but only increased annual Federal system resources about 1 aMW. The Study includes the following other Federal system resources:

(1) Small hydro (Elwah and Glines Hydro through September 30, 2009, and Dworshak/Clearwater Small Hydropower), wind (shares of Foote Creek 1, 2, and 4 wind projects; Stateline wind project; Condon wind project; Nine Canyon wind project; and Klondike I wind project), and a small amount of solar resources (Ashland solar project and White Bluffs solar). See Documentation, WP-07-E-BPA-45A, Sections 2.4.through 2.6, Table A-23, Federal Non-Utility Generating Resources by Project;

(2) Federal renewable resources include the Georgia-Pacific Wauna (formerly James River Wauna) cogeneration project and for FY 2009, BPA's share of the Klondike III wind project. *See* Documentation, WP-07-E-BPA-45A, Sections 2.4.through 2.6, Table A-8, *Federal Renewable Resources*; and

(3) The generation from the Columbia Generating Station incorporating an updated maintenance schedule for FY 2009. *See* Documentation, WP-07-E-BPA-45A, Sections 2.4 through 2.6, Table A-10, *Federal Large Thermal*.

The Non-Utility Generation and Renewable Resources generation estimates are provided by BPA, using actual project output data or estimates provided by the project owner. The generation estimates for the Columbia Generating Station nuclear power plant are provided by BPA using information provided by Energy Northwest, Inc.

Section 8. Treatment of Federal System Contracts

Q. Please describe how BPA treats Federal system contract obligations and contract purchases in the Study.

A. BPA's firm requirements PSC obligations, other signed contract obligations, and contract purchases are considered firm and are assumed to be met regardless of weather, water, or economic conditions. These contracts are categorized as: (1) PSC obligations; (2) power or exchange contracts; (3) capacity or capacity-for-energy exchange contracts; (4) power payments for services; and (5) power commitments under international treaty.

These load obligations are summarized monthly for energy in average megawatts, in the Documentation, WP-07-E-BPA-45A, Section 2.3, Tables 2.3.1 through 2.3.3, *Loads and Resources-Federal System, (2002 PSC Sales), (Slice Sales), (Exports)*, and *(Intra-Regional Transfers (Out))*. These contracts are detailed monthly for energy in aMW, HLH MWh, and LLH MWh, in the Documentation, WP-07-E-BPA-45A, Sections 2.4 through 2.6, Table A-2, *Federal Exports*, Table A-16, *Federal*

Intra-Regional Transfers (Out), and Table A-22, *BPA Power Sales Contracts* for the rate period.

For FY 2007-2008, BPA's other contract purchase estimates did not change from the WP-07 Final Proposal. For FY 2009, BPA's other contract purchase estimates were updated to include BPA's purchase of 13.4 aMW under the Excess Requirements Energy (ERE) from some Slice customers. This contract purchase resulted from a Letter Agreement that settled the implementation of Exhibit N of the Block and Slice Power Sales Agreement for FY 2008-2011. This contract expires September 30, 2011.

BPA's expected contract purchases are summarized monthly for energy in average megawatts, in the Documentation, WP-07-E-BPA-45A, Section 2.3, Tables 2.3.1 through 2.3.3, *Loads and Resources-Federal System*, (*Imports*), *(Non-Federal Canadian Entitlement Return for Canada), and (Intra-Regional Transfers (In)).* The monthly energy in aMW, HLH MWh, and LLH MWh, is detailed in the Documentation, WP-07-E-BPA-45A, Sections 2.4 through 2.6, Table A-5, *Federal Imports*, Table A-15, *Canadian Entitlement Return for Canada*, and Table A-16, *Federal Intra-Regional Transfers (In)*.

In addition, the Study assumes additional power purchases for the Federal system to meet forecasted firm annual energy deficits in FY 2007-2009. Under the Inventory Solution outlined in the Slice costing table in the Slice contract, these additional purchases are considered firm Federal resources to augment the resource stack in order to meet deficits under 1937 water conditions. For FY 2007-2008, BPA's augmentation purchase estimates did not change from the WP-07 Final Proposal. For FY 2009, BPA's change in load and contract obligations and updates in resources and contract purchases caused BPA's augmentation purchase estimate to change. For this Study, Federal system augmentation purchase estimate increased annually from 271 aMW to 341 aMW. The estimate of augmentation purchases are shown in the Documentation, WP-07-E-BPA-45A, Section 2.3, Tables 2.3.1 through 2.3.3, *Loads and Resources-Federal System*, *(Augmentation Purchases)*. The firm requirements PSC obligations, other signed contract obligations, and contract purchases data is provided to the Risk Analysis Study, WP-07-E-BPA-48.

Q. Please describe how BPA's surplus firm power contracts with Pacific Southwest (PSW) utilities are treated in the Study.

A. This analysis includes several contracts with the PSW utilities that contain power sales and capacity-for-energy exchange agreements. This Study assumes the contracts with the cities of Burbank, Glendale, and Pasadena are capacity-for-energy exchange agreements throughout the study period. *See* Documentation, WP-07-E-BPA-45A, Sections 2.4 through 2.6, Table A-2, *Federal Exports*.

Q. Please describe how BPA treats augmentation purchase contracts in the Study.

A. This analysis includes both signed and projected augmentation purchases to meet annual firm Federal system energy needs. For FY 2007-2008, the BPA's augmentation purchase estimates did not change from the WP-07 Final Proposal. For FY 2009, changes in BPA's load and contract obligations and updates in resources and contract purchases caused BPA's augmentation purchases to change. For this Study, Federal system augmentation purchase estimates increased annually from 271 aMW to 341 aMW.

For FY 2007, the Study includes both executed and forecasted BPA augmentation purchases. BPA's executed augmentation contract purchases averaged 106 aMW and expired December 31, 2006. In FY 2007, BPA forecasts that it will need 179 aMW in addition to the 106 aMW it has already purchased, to meet annual energy needs. These augmentation purchase estimates for FY 2007 were not updated from the WP-07 Final Proposal. The 106 annual average megawatts of executed augmentation contracts for FY 2007 are included in the Documentation, WP-07-E-BPA-45A, Sections 2.4 through 2.6. Table A-16, *Federal Intra-Regional Transfers (In), Other Entities to BPA*. The forecasted 179 aMW of augmentation purchases for FY 2007 is shown monthly for energy, in average megawatts, in the Documentation, WP-07-E-BPA-45A, Section 2.3, Table 2.3.1, *Loads and Resources-Federal System, (Augmentation Purchases)*.

For FY 2008, the forecast of annual augmentation purchases needed to meet BPA's annual energy needs is estimated to be 179 aMW. This augmentation purchase estimate for FY 2008 was not updated from the WP-07 Final Proposal. The forecast augmentation purchases for FY 2008 is shown monthly for energy, in average megawatts, in the Documentation, WP-07-E-BPA-45A, Section 2.3, Table 2.3.2, *Loads and Resources-Federal System, (Augmentation Purchases)*.

For FY 2009, the annual augmentation purchase estimates were updated to 341 aMW, an increase of 71 aMW from the WP-07 Final Proposal due to changes in BPA's load obligations and resources. The forecast augmentation purchases for FY 2009 is shown monthly for energy, in average megawatts, in the Documentation, WP-07-E-BPA-45A, Section 2.3, Table 2.3.3, *Loads and Resources-Federal System, (Augmentation Purchases)*.

The augmentation purchase estimates for FY 2007-2009 are considered firm Federal system resources to augment the Federal resource stack under the Inventory Solution to meet Federal system firm deficits, under 1937 water conditions, as outlined in the Slice costing table under the Slice Contract. These augmentation purchase projections are assumed to be purchased uniform across all hours and are summarized below in Table 8-1.

Table 8-1
Projected Federal System Augmentation Purchase
Fiscal Year Annual Average

Energy in aMW	**2007**	**2008**	**2009**
Augmentation Purchase	179	179	341

The monthly energy from these contracts, in aMW, HLH MWh, and LLH MWh, are inputs for the Supplemental Risk Analysis Study, WP-07-E-BPA-48.

Section 9. Federal System Transmission Losses

Q. Please describe BPA's treatment of Federal system transmission losses in the Study.

A. Federal system transmission loss estimates are treated as generation reductions in the Study. The transmission losses are calculated as 2.82 percent of the energy output for all Federal system hydro, small and large thermal, renewable, non-utility generation resources, and contract purchases. This reduction allows transmission losses to be calculated monthly and to vary by water year. BPA's Transmission function provided the analysis of expected Federal system transmission loss factors for energy and peak load conditions. The Federal system transmission loss factors used in this Study were developed in 1992 and reaffirmed by Transmission in 1994. These studies concluded the Federal system loss factors for BPA's transmission system are 2.82 percent for energy and 3.35 percent peak when averaged over the year.

The loss factors have several components that combine to give the estimate of losses typically associated with Federal system generation: (1) step-up transformers to the high voltage transmission network; (2) high voltage network distribution; (3) transfers through adjacent networks; and (4) step-down transformers to BPA customer meters. The estimated magnitude of those loss factor components for energy is as follows:

(1) Step-up transformers between the Federal generation and the transmission network of 0.31 percent;

(2) Network loss factor of 1.90 percent;

(3) Some loads are transfer customers, which have additional losses crossing other transmission networks averaging 0.34 percent; and

(4) Some loads have step-down transformer losses of 0.27 percent.

These assumed loss factors for load delivery to BPA customers have not changed since 1992.

For FY 2007-2008, the Federal system transmission loss estimates were not changed from the WP-07 Final Proposal. For FY 2009, Federal system transmission loss estimates were updated due to changes in the forecast of Federal system generation and contract purchases.

The Federal system surplus energy availability reflects Federal system transmission losses that vary by water year and is consistent with the Supplemental Risk Analysis Study, WP-07-E-BPA-48. *See* Documentation, WP-07-E-BPA-45A, Section 2.3, Tables 2.3.1 through 2.3.3, *Loads and Resources-Federal System (Federal Transmission Losses).*

Section 10. PNW Total Regional Hydro Resources for the Market Price Forecast Study

Q. Please describe the treatment of the regional hydro resources used in the Study.

A. To provide an additional input for the secondary revenue analysis used in the Supplemental Market Price Forecast Study, WP-07-E-BPA-47, the Study developed a PNW total regional hydro resource stack for FY 2007-2009. The PNW total regional hydro resource stack was not changed from the WP-07 Final Proposal. BPA will update the regional hydro resources for the final Supplemental Proposal. The regional hydro resources include all regional regulated and independent hydro projects, plus regional non-utility generation (NUG) hydro projects. BPA estimates the monthly regional hydro generation energy for each of the 50-water years (August 1928 through July 1978) using HYDSIM. The hydro data is then formatted to fiscal year format to be consistent with the Study. The generation estimates for the set of NUG hydro projects are not produced in the hydro regulation study; the individual NUG project owners provide these estimates. The total regulated, independent, and NUG regional hydro projections are summarized for 50-water years for FY 2007-2009 in the Documentation, WP-07-E-BPA-45A, Section 2.7, Tables 2.7.1 through 2.7.3, *Total Pacific Northwest Regional Hydro Resources*. These estimates are provided to the Market Price Forecast Study, WP-07-E-BPA-47.

Q.	*Does this conclude your testimony?*

A.	Yes.

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TESTIMONY of

RONALD J. HOMENICK and ALEXANDER LENNOX

Witnesses for Bonneville Power Administration

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TESTIMONY of

RONALD J. HOMENICK and ALEXANDER LENNOX

Witnesses for Bonneville Power Administration

SUBJECT: SUPPLEMENTAL REVENUE REQUIREMENT STUDY

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Ronald J. Homenick and my qualifications are contained in WP-07-Q-BPA-17.

A. My name is Alexander Lennox and my qualifications are contained in WP-07-Q-BPA-30.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to sponsor the revisions to the generation revenue requirement study to be used to revise power rates for fiscal year (FY) 2009. This testimony also sponsors the Supplemental Revenue Requirement Study (Study), WP-07-E-BPA-46, and the two volumes of the Supplemental Documentation of the Revenue Requirement Study (Documentation), WP-07-E-BPA-46A and WP-07-E-BPA-46B.

Q. How is your testimony organized?

A. Our testimony is organized in three sections. Section 1 is the introduction and purpose of the testimony. Section 2 addresses changes made to forecasts in the Study. Section 3 addresses potential changes that may be incorporated in the final Supplemental Proposal.

Section 2: Generation Revenue Requirement

Q. Are you proposing any changes to the methodology used to determine the generation revenue requirement for FY 2009?

A. No. We are using the same methodology to determine revenue requirements as it has used since the 1987 Wholesale Power and Transmission Rate Filing. The basis for revenue requirements is total accrued expenses projected for each year of the rate period, displayed in an income statement. In addition, a cash flow statement is used to determine whether additional net revenues are required to cover the amortization payments scheduled by the repayment study and the cash required for risk mitigation. *See* Study, Section 1.1, WP-07-E-BPA-46.

Q. Are you proposing changes to the expense and capital program levels that were included in the WP-07 Final Proposal?

A. Yes. Certain expense program expense forecasts have been revised. However, most of the program level forecasts included in the WP-07 Final Proposal are retained in this updated FY 2009 generation revenue requirement because there is no new information that would warrant a change.

Q. Please describe the updates you have made to the expense program levels.

A. First, the operations and maintenance expense forecast for the Columbia Generating Station (CGS) was revised upward by $31.5 million to reflect more recent estimates of future requirements. Second, the Long-Term Contract Generating Resource Projects expense forecast was increased by $6 million to account for the power purchase expense associated with the acquisition of the output of the Idaho Falls bulb turbine project. *See* Supplemental Load Resources Study, WP-07-E-BPA-45, 20. Third, forecast Renewables costs have been increased by $11.5 million to account for (1) a new contract to purchase a portion of the output of the Klondike III Wind Project, and (2) increased projected spending levels for renewable resource facilitation and research and development activities made possible by higher projected Green Tag revenues. *Id*. Fourth, the expense forecast for Energy Efficiency projects was increased by $9 million. However, this is a reimbursable program so there is a corresponding increase in the forecast of miscellaneous revenues. Fifth, augmentation costs were increased to account for the cost of serving higher FY 2009 loads, although the investor-owned utility (IOU) deferred augmentation expense, which falls under the umbrella of the Residential Exchange Program (REP) settlements was removed. The net increase in the forecast of augmentation costs is $13 million. Sixth, Other Power Purchases (short-term balancing purchases) also increased slightly to account for updates to loads and resources. Seventh, the forecast for direct service industry (DSI) Monetized Power Sales was reduced by $4 million based on changes in the manner that DSI contracts are being implemented. *See* Supplemental Risk Analysis Study, WP-07-E-BPA-48, Section 2.4.7. Finally, the Residential Exchange/IOU Settlement Benefits line item has been modified to delete the costs of the REP settlements and to reflect the gross REP cost calculated as part of this Supplemental Proposal.

Q. Has BPA's forecast of capital investments changed since the publication of the WP-07 Final Proposal?

A. No. The forecast of capital investments for FY 2008 and FY 2009 is the same as in the WP-07 Final Proposal. However, two years of the forecast period in the WP-07 Final Proposal, FY 2006 and FY 2007, have now passed. The capital spending and financing activities for those years are now reflected in the actual data incorporated into the Study.

Q. What changes have those actions made to the 2009 generation revenue requirement?

A. The depreciation/amortization forecast reflects actual capital investment additions and retirements in those years. Energy Northwest debt service and the repayment study database have been updated for actual debt management results, including Debt Optimization Program (DOP) actions, in those years as well.

Q. Have BPA's repayment obligations changed since the publication of the WP-07 Final Proposal?

A. Yes. The Bureau of Reclamation revised its calculation of BPA's irrigation assistance obligation due to be paid in FY 2009. The obligation was increased slightly, from $6.6 million to $7.2 million. This change has been incorporated in the repayment study.

Q. Is the schedule of Federal amortization for FY 2007-2009 being modified in the Initial Supplemental Proposal?

A. No. BPA has chosen to abide by the original amortization plan for the FY 2007-2009 rate period. The final schedule of annual amortization payments for the rate period in the WP-07 Final Proposal was the result of an amortization shift, necessary to accommodate expected cash flows, that was applied in the Revised Revenue Test. Approximately $82 million of planned amortization in FY 2009 was shifted to FY 2007 and FY 2008 without changing the total amortization for the rate period. *See* 2007 Wholesale Power Rate Case Final Proposal, Revenue Requirement Study, WP-07-FS-BPA-02, 4. The resulting FY 2007 payment has already been made and the FY 2008 payment is expected to be incorporated into current year debt management actions as planned. In addition, future BPA debt management actions, particularly related to Debt Optimization, have been constructed around the scheduled amortization. Consequently, the originally scheduled amortization for FY 2009 that was the result of the shift will be used in the development of this revenue requirement.

Section 3: Slice/Debt Optimization and Debt Service Reassignment Demonstration

Q. What is the Slice/Debt Optimization and Debt Service Reassignment Demonstration?

A. In connection with the settlement of the Slice litigation in November 2006, BPA signed a Memorandum of Understanding (MOU) providing, in part, that as part of any general rate case BPA would demonstrate that "rates of each of BPA's business lines (Transmission

Business Line (TBL) and Power Business Line (PBL)) are no higher with the DOP than they would have been in the absence of the DOP." *See* Slice Settlement Agreement, Exhibit D, Section B(2). The MOU further provided that "BPA will continue to so demonstrate achievement of this principle annually and in the next and subsequent general wholesale power and transmission rate proceedings so long as new DOP refinancings occur." *Id*. This demonstration was first included in the 2008 Transmission rate case. *See* Revenue Requirement Documentation, TR-08-FS-BPA-01A, Chapter 14.

Q. What changes to the Revenue Requirement Study and Documentation were made to facilitate the demonstration for this rate proceeding?

A. Pursuant to the MOU, BPA agreed to include Sections B.1, B.2, B.3, and B.4 of the MOU in the Revenue Requirement Study, along with a description of the DOP-related costs that are proposed to be included in power rates in the Documentation. *See* Documentation, WP-07-E-BPA-46A, Section 11.

Q. Please explain the DOP-related costs that are included in the power rates established in this proceeding.

A. The revenue requirement income statement includes non-Federal debt service which includes the principal and interest payments anticipated for Energy Northwest. *See* Study, WP-07-E-BPA-46, Table 5A. The development of these costs, which incorporate all DOP transactions made through FY 2007, are explained and detailed in Section 8 of the Documentation, WP-07-E-BPA-46A.

Section 4: Possible Modifications and Adjustments for Final Supplemental Proposal

Q. Could there be additional changes affecting the Study in the final Supplemental Proposal?

A. Yes. The repayment study database may be updated for any FY 2008 debt management actions completed prior to the final Supplemental Proposal. FY 2008 ending reserve estimates will be updated for the final Supplemental Proposal, which could affect such things as interest credit amounts, key risk modeling data assumptions, and probability results. The repayment study will also reflect any changes in non-Federal debt management assumptions.

Q. Are other Revenue Requirement Study changes possible in the final Supplemental Proposal?

A. Yes, there are several areas of possible change. First, certain anticipated processes or events could result in the need to update fish and wildlife program spending and capital investment forecasts, as discussed next.

Second, the irrigation assistance payments included in the repayment study will be updated to reflect any revisions to the amounts of financial assistance required from power rates that the Bureau of Reclamation might provide in their annual transmittal to BPA. Third, if legislation concerning a settlement agreement by and between BPA and the Spokane Tribe is enacted by Congress, the associated costs will be incorporated into the revenue requirement. Fourth, if a judgment related to any pending litigation or any agreement settling such litigation results in a financial impact on BPA, those revenue or cost changes will be included. Each of these changes could result in higher costs. Fifth, BPA may update its interest rate forecasts that might raise or lower Federal or non-Federal debt service. Finally, any forecast program cost changes due to additional cost reductions or increases, mandatory expenditures due to law or regulation, or policy initiatives will be updated in the final Supplemental Proposal.

Q. What are some of the possible changes in fish and wildlife costs?

A. BPA expects to receive a final Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp) regarding the impacts of the FCRPS on salmon and steelhead listed under the Endangered Species Act from NOAA Fisheries in May 2008, which may result in additional costs. In addition, BPA may enter into long-term memoranda of agreement with regional entities to implement specific projects relating to the FCRPS BiOp and other activities for fish and wildlife. BPA plans to include estimates of any expected changes in the program spending forecasts for the fish and wildlife program or capital investments as a result of implementing the final FCRPS BiOp, and the costs of any associated long-term agreements, in its final Supplemental Proposal. In addition, the annual plant-in-service forecast for the Columbia River Fish Mitigation project will be revised if BPA receives an updated forecast from the Corps of Engineers.

Q. *How will parties have an opportunity to see and understand these forecasts prior to the Final Proposal?*

A. BPA will hold a workshop external to this proceeding but prior to the final Supplemental Proposal to provide an opportunity to any interested person or organization to review the program level changes from the WP-07 Final Proposal. This workshop will address the changes in program levels that are reflected in the Supplemental Proposal, as well as any subsequent changes that are necessary in the final Supplemental Proposal, such as for fish and wildlife costs. It will provide interested parties an opportunity to review BPA's updated forecasts, including the forecast of fish and wildlife costs, and to provide any additional information BPA may not have captured. BPA will take comment, issue a close-out report following the workshop, and then will reflect the results in the FY 2009 revenue requirement in the final Supplemental Proposal. *See also* Bliven, *et al.*, WP-07-E-BPA-52.

Q. *Does this conclude your testimony?*

A. Yes.

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TESTIMONY of

ROBERT J. PETTY, SIDNEY L. CONGER, JR., and ROBERT W. ANDERSON

Witnesses for Bonneville Power Administration

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TESTIMONY of

ROBERT J. PETTY, SIDNEY L. CONGER, JR., and ROBERT W. ANDERSON

Witnesses for Bonneville Power Administration

SUBJECT: SUPPLEMENTAL MARKET PRICE FORECAST

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Robert J. Petty. My qualifications are contained in WP-07-Q-BPA-44.

A. My name is Sidney L. Conger, Jr. My qualifications are contained in WP-07-Q-BPA-10.

A. My name is Robert W. Anderson. My qualifications are contained in WP-07-Q-BPA-01.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to describe the Supplemental Market Price Forecast Study for the WP-07 Supplemental Proposal. This testimony supports data and information contained in WP-07-E-BPA-47 and WP-07-E-BPA-47A.

Section 2: Uses of the Market Price Forecast

Q. How was the Market Price Forecast Study used in the WP-07 Final Proposal?

A. For the WP-07 Final Proposal, the Market Price Forecast Study was used for the following purposes: (a) estimating the forward price for the Residential Exchange Program (REP) settlement benefits for the IOUs and Direct Service Industry (DSI) smelter payments for FY 2008 and 2009; (b) estimating the uncertainty surrounding IOU REP settlement benefits and DSI smelter payments; (c) informing the secondary revenue forecast; and (d) providing a series of price inputs used for the risk analysis.

Q. *Is the Market Price Forecast Study being used in this Supplemental Proposal for the same purposes as it was used in the WP-07 Final Proposal?*

A. Most, but not all. The Market Price Forecast Study for the Supplemental Proposal is used for: (a) estimating the forward price for the DSI smelter payments; (b) estimating the uncertainty surrounding DSI smelter payments; (c) informing the secondary revenue forecast, and (d) providing a price input used for the risk analysis.

Q. *Why is the Market Price Forecast Study for the initial Supplemental Study not being used to estimate the forward price for the IOU REP Settlement benefits?*

A. Due to the opinions of the U.S. Court of Appeals for the Ninth Circuit regarding the REP Settlement Agreements, BPA is no longer providing benefits pursuant to the REP settlements, and so there is no need for a forward price estimate for the REP settlement benefits. *See* Bliven, *et al.*, WP-07-E-BPA-52.

Section 3: Market Price Forecast

Q. *For this Supplemental Study, what inputs did you review for the Market Price Forecast Study?*

A. First, the load forecast for AURORA was reviewed. For the WP-07 Final Proposal, BPA relied on a load forecast from the WECC 10-Year Coordinated Plan Summary (2005-2014). Since the time of the Final Studies, the WECC 10-Year Coordinated Plan Summary (2006-2015) has been released that includes an updated load forecast. In reviewing the two forecasts, there was a minimal change in the PNW load forecasts.

Q. *What was the second input reviewed?*

A. The second input reviewed was resource additions in the PNW. Two new natural gas plants, Port Westward and Mint Farm, are now operating that were not included in the WP-07 Final Proposal. Cherry Point, another natural gas plant, is expected to be operating shortly. Also, additional wind resources have come on-line since the WP-07 Final Proposal.

Q. What was the third input reviewed?

A. The third input reviewed was the natural gas price forecast. The natural gas price from the WP-07 Final Proposal is tracking well with actual prices. From January 2006 to November 2007 the percentage difference between forecast prices and actual prices at Henry Hub averaged less than 5 percent. Furthermore the WP-07 Final Proposal assumed a generally tight balance of supply and demand in the natural gas market. The Final Proposal assumed that North American conventional production basins are mature, but liquefied natural gas would begin to add significantly to supply in 2008. The Final Proposal also expected growth in natural gas demand, but with important price risks. These underlying fundamentals remain valid and we are not updating the WP-07 Final Proposal gas price forecast for this initial Supplemental Proposal.

Q. What was the last input reviewed?

A. The last input reviewed was the hydro generation forecast from the Load Resource Study. The hydro generation forecast has not been updated since the WP-07 Final Proposal, so that forecast remains the most current. *See* Supplemental Load Resource Study, WP-07-E-BPA-45.

Q. Are you updating the Market Price Forecast Study to incorporate the above referenced changes?

A. Not at this time. We did not believe we had sufficient time to incorporate these few updates in the timeframe provided by the original schedule for preparing the Study and other material for this initial Supplemental Proposal. In any case, the few changes to the inputs described above are, for purposes of the market price forecast, minor. Even without incorporating the above referenced updates, the WP-07 Final Proposal Market

Price Forecast Study remains reasonable as of the date of this testimony. However, the Study components will be reviewed again and updated as appropriate, including the above referenced updates, for the final Supplemental Proposal.

Section 4: WP-07 Final Proposal Market Price Forecast

Q. How was the price forecast developed that is used to inform the secondary revenue forecast?

A. Briefly, the AURORA model is run for each of the 50 different regional generation levels developed by the Load Resource Study. The result is 50 different prices for each month for both heavy load hours (HLH) and light load hours (LLH). All other inputs except the hydro generation levels are held constant. For more information about how the price forecast for informing the secondary revenue forecast is developed, *see* Supplemental Risk Analysis Study, WP-07-E-BPA-48.

Q. What were the results of the WP-07 Final Proposal price forecast developed to inform the secondary revenue forecast?

A. Table 1 summarizes the average of the 50 different AURORA runs by HLH and LLH.

Table 1
Summary of Price Forecast for
Secondary Revenue Forecast

	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Avg
HLH	52.55	58.86	59.29	54.78	55.65	52.36	39.35	32.99	30.73	40.20	48.67	51.41	48.07
LLH	45.13	48.64	51.39	47.26	50.75	48.13	38.29	23.35	22.28	37.23	43.91	47.28	41.97

Q. *How was the price forecast developed that is used to estimate the uncertainty surrounding DSI smelter payments and to provide a price input used for the risk analysis?*

A. Briefly, the AURORA model is run 3,000 different times to develop monthly HLH and LLH prices. The model is run in a stochastic manner altering natural gas prices, hydro generation levels and load levels. The result of the AURORA run is 3,000 prices by month for HLH and LLH. For more information about how the price forecast is used for estimating the uncertainty surrounding DSI smelter payments and providing a price input used for the risk analysis, *see* Supplemental Risk Analysis Study WP-07-E-BPA-48.

Q. *What were the results of the WP-07 Final Proposal price forecast developed for estimating the uncertainty surrounding DSI smelter payments and providing a price input used for the risk analysis?*

A. Table 2 summarizes the average of the 3,000 prices by month for HLH and LLH.

Table 2
Summary of Price Forecast for
DSI Payment Uncertainty and Risk Analysis

	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Avg
HLH	58.04	64.39	68.01	66.49	65.70	58.03	42.05	29.79	33.76	43.52	55.96	53.56	53.27
LLH	49.79	53.53	56.27	51.29	61.24	51.98	40.01	28.76	24.28	39.86	47.35	51.90	46.36

Q. *How was the price forecast developed that is used to estimate of the forward price for DSI smelter payments?*

A. AURORA is run in a deterministic mode based on average hydroelectric generation levels, average loads and the median natural gas prices. AURORA is run for every hour of the year. Every hour of the year is then averaged to derive an annual average.

Q. *What was the result of the WP-07 Final Proposal estimated forward price for the DSI smelter benefits?*

A. The average price for FY 2009 was $50.68/MWh.

Section 5: Expected final Supplemental Proposal Updates

Q. *What aspects of the Market Price Forecast Study are expected to be updated for the final Supplemental Proposal?*

A. First, the load forecast will be updated using the latest 10-Year Coordinated Plan. Second, Port Westward will be added to the resource additions, as well as Mint Farm, Cherry Point and other natural gas plants that are expected to be on-line soon. Also, new and nearly complete wind plants will be added to the resource stack. Third, the natural gas fundamentals will be evaluated and if there are material changes in the natural gas market, a revised natural gas prices will be incorporated. Fourth, if a new hydro generation forecast is available, it too will be used in the final Market Price Forecast Study.

Q. *For the final Supplemental Proposal, do you expect any methodology changes to the Market Price Forecast Study?*

A. No methodology changes to the Supplemental Market Price Forecast Study are anticipated.

Q. *Does this conclude your testimony?*

A. Yes.

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TESTIMONY of

RANDY B. RUSSELL, MICHAEL R. NORMANDEAU, BYRNE E. LOVELL,

SIDNEY L. CONGER, JR., ARNOLD L. WAGNER, and KENNETH J. MARKS

Witnesses for Bonneville Power Administration

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TESTIMONY of

RANDY B. RUSSELL, MICHAEL R. NORMANDEAU, BYRNE E. LOVELL,

SIDNEY L. CONGER, JR., ARNOLD L. WAGNER, and KENNETH J. MARKS

Witnesses for Bonneville Power Administration

SUBJECT: SUPPLEMENTAL RISK ANALYSIS

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Randy Russell and my qualifications are contained in WP-07-Q-BPA-47.

A. My name is Michael Normandeau and my qualifications are contained in WP-07-Q-BPA-43.

A. My name is Byrne Lovell and my qualifications are contained in WP-07-Q-BPA-32.

A. My name is Sid Conger and my qualifications are contained in WP-07-Q-BPA-10.

A. My name is Arnold Wagner and my qualifications are contained in WP-07-Q-BPA-50.

A. My name is Ken Marks and my qualifications are contained in WP-07-Q-BPA-36.

Q. What is the purpose of your testimony?

A: The purpose of this testimony is to describe BPA's assumptions used, and the analysis performed, to complete the risk analysis and subsequent risk mitigation package for the WP-07 Supplemental Proposal for the FY 2009 rates, and to sponsor the Supplemental Risk Analysis Study (Study), WP-07-E-BPA-48, and Supplemental Risk Analysis Documentation (Documentation), WP-07-E-BPA-48A.

Q. How is your testimony organized?

A. This testimony is organized into six sections including this introductory section. The second section discusses the Operational Risk Model. In Section 3, the testimony addresses Modeling Operating Risks. In Section 4, we discuss the development of the secondary energy revenue forecast. Section 5 addresses the Non-Operating Risks and the Non-Operating Risk Model (NORM). Section 6 addresses the Accrual-to-Cash (ATC) Adjustments.

Section 2: Operational Risk Model (RiskMod)

Q. Please briefly describe RiskMod.

A. RiskMod is an operational risk analysis model that estimates Power Services net revenues under varying conditions of loads, resources, natural gas prices, forward market electricity prices, transmission expenses, and aluminum smelter benefit payments. RiskMod is comprised of a set of risk simulation models, collectively referred to as RiskSim; a set of computer programs that manages data referred to as Data Manager; and RevSim, a model that calculates net revenues (revenues less expenses). *See* Study and Documentation, WP-07-E-BPA-48 and WP-07-E-BPA-48A.

Q. What risks are reflected in RiskMod?

A. Operating risks reflected in RiskMod are the following:

- Federal Hydro Generation
- PNW Hydro Generation
- PNW Loads
- BPA Loads
- California Hydro Generation
- California Loads
- Natural Gas Prices
- Columbia Generation Station (CGS) Nuclear Plant Generation
- DSI Benefits
- Wind Project Generation

- Power Services Transmission and Ancillary Services Expense
- Forward Market Electricity Prices
- 4(h)(10)(C) credit

Also, while not quantified in RiskMod, RiskMod supports the quantification of the spot market electricity price risk by AURORA.

Q. What are the risk simulation models (RiskSim) used in this Study?

A. The risk simulation models are the following:

- PNW Load Risk Model
- California Load Risk Model
- Natural Gas Price Risk Model
- CGS Nuclear Plant Risk Model
- DSI Benefit Risk Model
- Wind Generation Risk Models
- Transmission Expense Risk Model
- Forward Market Price Risk Model

Q. With which studies, processes, and models does the Study interact?

A. The Study interacts with the Rate Analysis Model (RAM), ToolKit Model, AURORA, the Revenue Forecast Study, and the Revenue Requirement Study.

Q. There is an iterative process between the RAM, RiskMod, and ToolKit when developing rates. Please describe this process.

A. In order to calculate Treasury Payment Probability (TPP) there is an iterative loop that must take place among the RAM, RiskMod and ToolKit. This process involves providing average annual surplus revenues, power purchase expenses, and section 4(h)(10)(C) credits from the RiskMod to the RAM. The RAM, in turn, provides RiskMod with a set of rates and expenses. Based on the information from the RAM, RiskMod estimates net revenue risk. These results are provided to the ToolKit, which then calculates Planned Net Revenues for Risk (PNRR) for a specific TPP. *See* Normandeau, *et al.*, WP-07-E-BPA-73 for a discussion regarding TPP. The PNRR from the ToolKit is included in the revenue requirement used to calculate rates in the RAM. This process is iteratively performed until the specified TPP is reached. *See* Study, WP-07-E-BPA-48, Graph 1.

Section 2.1: Changes in Risk Modeling Since the WP-07 Final Proposal

Q. Have any of the risk factors changed since the WP-07 Final Proposal?

A. Yes, the investor-owned utility (IOU) Residential Exchange Program (REP) Benefit risk that was considered in the WP-07 Final Proposal does not exist in this Supplemental Proposal.

Q. Why was the IOU REP Benefit risk removed in this Supplemental Proposal?

A. It was removed as part of BPA's response to recent Court rulings related to the REP settlements. *See* Bliven, *et al.*, WP-07-E-BPA-52. In the WP-07 Final Proposal, the variability of REP settlement benefits to IOUs was modeled in the ToolKit. This was necessary because the REP settlement benefits depended in part on a proxy for the market price of power, and since that could not be known in advance, there was financial uncertainty for BPA. The REP implementation, as proposed by BPA, creates very little financial uncertainty for BPA. *See* Marks, *et al.*, WP-07-E-BPA-62. Under BPA's proposed Average System Cost (ASC) Methodology, ASC levels will be determined prior to the final Supplemental Proposal, and a PF exchange rate will be determined in the rate case, leaving only uncertainty over exchange loads. The variability over exchange loads will be minimized through BPA's proposed Lookback amortization procedures.

Q. *What changes were made to the risk simulation models since the WP-07 Final Proposal?*

A. While the methodologies used in the risk models did not change from the WP-07 Final Proposal, the DSI Benefit Risk Model, the CGS Nuclear Plant Risk Model, the Klondike Wind Project Risk Model, and the Transmission Expense Risk Model were updated with revised data.

Q. *Why were changes made to the DSI Benefit Risk Model since the WP-07 Final Proposal?*

A. Updates were made to reflect changes in the implementation of the DSI contracts. Subsequent to DSI contract execution in 2006, the following three things have occurred that impact the amount and risk of DSI benefit payments: (1) all three aluminum DSIs selected the 5-year option which provides for averaging power purchase prices and the PF rate over the term of the contract; (2) DSI benefit payments for 460 aMW were reduced 8 percent each year for FY 2007-2009, resulting in a financial benefit based on the difference between the price paid on forward market electricity purchases that have been acquired and the lowest-cost flat PF rate up to a maximum of $11.04/MWh ($44.5 million/year); and (3) unused benefits (100 aMW) of one aluminum DSI were allocated to the other two aluminum DSIs effective October 1, 2007. The 8 percent reduction does not apply to the 100 aMW. The financial benefit payment for this portion is established annually and is based on the difference between the price paid on market electricity purchases that have not yet been acquired and the lowest-cost annual flat PF rate up to a maximum of $12.00/MWh or $10.5 million/year for FY 2009. *See* Study and Documentation, WP-07-E-BPA-48 and WP-07-E-BPA-48A, regarding DSI Benefits.

Q. *Why were changes made to the CGS Nuclear Plant Risk Model since the WP-07 Final Proposal?*

A. Changes were made to account for revisions in the forecast monthly output of CGS in the Load Resource Study. *See* Supplemental Load Resource Study, WP-07-E-BPA-45.

Q. *Why were changes made to the Klondike Wind Project Risk Model since the WP-07 Final Study?*

A. Changes were made to account for the inclusion of purchases from Klondike III starting in December 2007. *See* Supplemental Load Resource Study, WP-07-E-BPA-45.

Q. *Why were changes made to the Transmission Expense Risk Model since the WP-07 Final Study?*

A. Changes were made to account for changes in BPA surplus energy sales resulting from revisions in the Load Resource Study. *See* Supplemental Load Resource Study, WP-07-E-BPA-45.

Q. *Do changes in BPA surplus energy sales account for all of the changes in transmission expenses for FY 2009?*

A. No. Pre-purchased transmission expenses for FY 2009 were understated by $15 million. This will be corrected in the Final Supplemental Study.

Q. *For the Supplemental Proposal, did you update and rerun the PNW Load Risk Model, California Load Risk Model, and Natural Gas Price Risk Model?*

A. No. The PNW Load Risk Model, California Load Risk Model, and Natural Gas Price Risk Model were not updated and rerun for the following reasons. First, BPA determined that PNW loads, California loads, and natural gas prices from in the Final Market Price Forecast Study, WP-07-FS-BPA-03, for the WP-07 Final Proposal remain appropriate for use in the Supplemental Proposal, however, these forecasts may be reviewed and updated as appropriate for the final Supplemental Proposal. *See* Petty, *et al.*, WP-07-E-BPA-66. Second, even though BPA believed it would not have had sufficient time to incorporate any possible revisions in estimates of risk in the timeframe provided by the original schedule for preparing the Study and other material for this Supplemental Proposal, BPA believes that the PNW load, California load, and natural gas price risks used in the WP-07 Final Proposal are still reasonable and appropriate for use in the Supplemental Proposal. This is due to the following reasons: (1) There are no changes in the load and natural gas price forecasts; (2) the inclusion of an additional one or two years of historical load and gas price data is expected to have only minor impacts on the estimates of risk, since the risk for these risk models were derived from 22 years of data for the PNW and California Load Risk Model and 16 years of data for the Natural Gas Price Risk Model; and (3) the simulated FY 2009 PNW load, California load, and natural gas price risk estimates shown in Graphs 3, 5, and 6 of the Documentation, WP-07-E-BPA-48A, are not expected to change materially, even if these risk models were run starting at the beginning of FY 2008. Nonetheless, for the final Supplemental Proposal, BPA will review these again and update the risk estimates, as appropriate.

Q. *For the Supplemental Proposal, did you update and rerun the Forward Market Price Risk Model?*

A. No. The Forward Market Price Risk Model uses variable monthly spot market electricity prices estimated by AURORA and forecast annual forward prices to simulate forward market price risk used in the DSI Benefit Risk Model. Since neither the variable monthly spot market electricity prices estimated by AURORA nor the forecast annual forward prices are being updated from the WP-07 Final Proposal, the Forward Market Price Risk Model was not updated and rerun. *See* Petty, *et al.*, WP-07-E-BPA-66.

Q. *For the Supplemental Proposal, did you update and rerun any of the Wind Generation Risk Models except for the Klondike Wind Project Risk Model?*

A. No. The average monthly wind generation values and generation risk reflected in the Wind Generation Risk Models were derived from the same historical generation data that were used to estimate the average monthly wind generation in the Supplemental Load Resource Study, WP-07-E-BPA-45. The wind generation values in the Supplemental Load Resource Study, with the exception of the addition of Klondike III, were not updated from the WP-07 Final Proposal. Accordingly, for consistency sake, except for Klondike, the wind generation values remain unchanged in the Wind Generation Risk Models.

Section 3: Risk Modeling

Section 3.1: Federal Hydro Generation

Q. *What does Federal hydro generation risk account for in the Study?*

A. Federal hydro generation risk is incorporated into RiskMod to account for the impact that various Federal hydro generation levels and Heavy Load Hour (HLH) and Light Load Hour (LLH) hydro generation shaping capability have on the quantity of energy that BPA has to buy and sell during HLH and LLH periods. This risk, coupled with price risk, is the largest risk Power Services faces.

Q. *Please briefly describe how this risk was modeled in the WP-07 Final Proposal.*

A. RiskMod randomly selects, by water year, monthly Federal hydro generation data and the associated HLH hydro generation ratios reported in output tables for the 50 historical water years. *See* Documentation, WP-07-E-BPA-48A, Tables 4-9. These output data are from a “continuous study” performed by the HydroSim model and the Hourly Operating and Scheduling Simulator (HOSS) model where hydro generation is calculated sequentially over all 600 months of the 50-water years. *See* Supplemental Load Resource Study, WP-07-E-BPA-45, regarding a continuous study by HydroSim. After an initial water year is selected for the first year of the rate period (FY 2007) for a given simulation, hydro generation data for a sequential set of three water years, starting with the water year selected for FY 2007, are selected from water years 1929-1978. When the end of the 50-water years is reached (at the end of water year 1978), monthly hydro generation data for water year 1929 is subsequently used.

Q. Why did you model Federal hydro generation data in a continuous manner?

A. Selecting hydro generation data in such a continuous manner captures the risk associated with various dry, normal, and wet weather patterns over time that are reflected in the 50-water year period.

Q. How does RiskMod select the water year for the first year of the rate period for Federal hydro generation?

A. RiskMod randomly selects the water year based on values sampled from a uniform probability distribution. The uniform probability distribution was selected for modeling hydro generation risk because it appropriately assigns equal probability to each of the 50-water years being sampled.

Q. When the end of the 50-water years is reached (at the end of water year 1978), what happens?

A. RiskMod starts over with water year 1929 so that all water years are equally represented in the three-year water sequences.

Q. Were any changes made to the water year sampling to accommodate the one-year rate period in this Supplemental Proposal?

A. No. The water year sequences for this Supplemental Proposal are the same as the water year sequences used in the WP-07 Final Proposal. In this Supplemental Proposal, the model was run for three years (FY 2007-2009) but only data for FY 2008-2009 was passed on to the ToolKit.

Q. *Were any adjustments made to the Federal hydro generation data in Tables 4-6 in the WP-07 Final Risk Study?*

A. Yes. Hydro generation adjustments were made to each year of the 50-water year data from the continuous study for FY 2007-2009 to reflect the refilling of non-treaty storage in Canada and to reconcile differences between the HydroSim study for FY 2006 and the HydroSim study for FY 2007.

Q. *What is non-treaty storage?*

A. Under the Columbia River Treaty, Canada was required to construct 15.5 million acre-feet (MAf) of storage at the Mica, Arrow, and Duncan projects. The United States was allowed to construct 5 MAf of storage at Libby Dam. BC Hydro also built storage on the Columbia River system beyond what was required by the Treaty (termed non-treaty storage), including storage behind Revelstoke Dam and an additional 5 MAf of usable storage at Mica. On occasion, BC Hydro has also made available 2 feet (0.26 MAf) of storage in Arrow above the normal full elevation of the Arrow reservoir.

Q. *What is the Non-Treaty Storage Agreement?*

A. In order to operate existing non-treaty space in Canada and to change the flows into the United States, additional agreements were required. A long-term agreement to operate non-treaty storage in Canada was signed in 1990, along with companion agreements with some mid-Columbia project participants. The 1990 Non-Treaty Storage Agreement (NTSA) is an agreement between BPA and BC Hydro that allows operation of some non-treaty storage in Canada, the most significant of which is 4.5 MAf of space in Mica (2.25 MAf for BPA [U.S. parties] and 2.25 MAf for BC Hydro) known as "Active Storage Space."

Q. *What circumstances brought about the need for the U.S. to refill non-treaty storage?*

A. The NTSA had an initial termination date of June 30, 2003. A one-year extension of that agreement resulted in initial termination on June 30, 2004. The initial termination date is the date when parties are no longer able to release water from non-treaty storage space and the 7-year refill period is initiated. When agreements were first negotiated for operation of non-treaty storage space, the Active Storage Space was full. Under terms of the agreement, the space must be refilled no later than 7 years after the initial termination date (June 30, 2011).

Q. *Were any changes made to the non-treaty storage adjustments used in the WP-07 Final Proposal?*

A. Yes. The non-treaty storage adjustments for FY 2008-2009 were updated for this Supplemental Proposal to reflect storage into non-treaty storage space that has been accomplished since the WP-07 Final Proposal.

Q. *In the WP-07 Final Proposal an adjustment to the hydro generation for FY 2007 was made to reconcile differences between the HydroSim study for FY 2006 and the HydroSim study for FY 2007. Was a similar adjustment made to the hydro generation for FY 2009 in this Supplemental Proposal?*

A. No. A similar adjustment was not made to the Federal hydro generation for FY 2009. At the time the WP-07 Final Proposal was being completed, differences between the ending reservoir levels in the HydroSim study for FY 2006 and the starting reservoir levels in the HydroSim study for FY 2007 were discovered. The adjustment to the hydro generation data for FY 2007 was made to correct for this difference in reservoir levels. A similar difference between FY 2008 ending reservoir levels and FY 2009 starting reservoir levels does not exist between FY 2008 and FY 2009 in this Supplemental Proposal.

Section 3.2: Pacific Northwest (PNW) Hydro Generation

Q. What does PNW hydro generation risk cover in the Study?

A. PNW hydro generation risk accounts for the impact that various PNW hydro generation levels have on monthly HLH and LLH spot market electricity prices estimated by AURORA.

Q. Please briefly describe how this risk is modeled.

A. RiskMod randomly selects, by water year, monthly PNW hydro generation data reported in output tables for the 50-water years. *See* Documentation, WP-07-E-BPA-48A, Table 1-3. These output data are from a "continuous study" performed by the HydroSim model where hydro generation is calculated sequentially over all 600 months of the 50-water year period. *See* Supplemental Load Resource Study, WP-07-E-BPA-45, regarding a continuous study by HydroSim. After an initial water year is selected for the first year of the rate period (FY 2007) for a given simulation, hydro generation data for a sequential set of three water years, starting with the water year selected for FY 2007, are selected from water years 1929-1978. When the end of the 50-water years is reached (at the end of water year 1978), monthly hydro generation data for water year 1929 is subsequently used.

Q. Why is PNW hydro generation data selected in a continuous manner?

A. Selecting hydro generation data in such a continuous manner captures the risk associated with various dry, normal, and wet weather patterns over time that are reflected in the 50-water year period.

Q. How does RiskMod align Federal and PNW hydro generation simulations?

A. When RiskMod selects the water year for the first year of the rate period for PNW hydro generation, it uses the same value sampled from a uniform probability distribution for Federal hydro generation.

Q. When the end of the 50-water years is reached (at the end of water year 1978), why did RiskMod sequentially use monthly PNW hydro generation data for water year 1929?

A. RiskMod starts over with water year 1929 so that all water years are equally represented in the 3-year water sequences.

Section 3.3: PNW and BPA Loads

Q. What PNW and BPA load risk does RiskMod account for in the Study?

A. PNW load risk is incorporated into the Study because PNW load variability affects monthly HLH and LLH spot market electricity prices. These price impacts in turn affect Power Services' surplus energy revenues and power purchase expenses. BPA load risk is incorporated into the Study to account for the impact that monthly PF load variability has on Priority Firm Power (PF) revenues, surplus energy revenues, and power purchase expenses.

Q. Please describe how PNW and BPA load risk are modeled.

A. PNW (and indirectly BPA) load variability is modeled in the PNW Load Risk Model such that annual load growth variability and monthly load swings due to weather conditions are both accounted for in one PNW load variability factor. BPA monthly load variability is derived such that the same percentage changes in PNW loads are used to quantify BPA load variability. Annual PNW (and indirectly BPA) load growth risk is modeled to simulate various load patterns through time using a mean-reverting, random-walk technique.

Q. Please describe the mean-reverting, random-walk technique used in this analysis.

A. The random-walk technique simulates various annual average load levels through time with the starting point for simulating annual average load in a given year being the annual average load level from the previous year. The mean-reverting technique causes simulated annual loads to tend to revert to the forecast loads as loads move further from forecast loads (either higher or lower). *See* Documentation, WP-07-E-BPA-48A.

Q. What load data did you use to calculate the annual load growth deviations for the PNW?

A. We used Western Electricity Coordinating Council (WECC) load data for the Northwest Power Pool Area from 1982-2004 to calculate the annual load growth deviations for the PNW. *See* Documentation, WP-07-E-BPA-48A, Table 14. We used the WECC data because it is the recognized best comprehensive source of load data for the western United States for load data.

Q. Please describe how the variability in monthly loads due to weather conditions was derived.

A. PNW (and indirectly BPA) monthly load swings due to weather conditions were derived from estimates of daily load standard deviation values for each of the 12 months. The source of these estimates was the 1996 Rate Case Marginal Cost Analysis Study (MCA) Documentation, WP-96-FS-BPA-04A.

Q. Why are monthly load standard deviations for weather conditions derived from daily load standard deviations in the Study?

A. Calculating monthly load standard deviations from historical load data by sorting historical load data for the same month (over a period of years) yields load standard deviations that include both the impact of load growth and weather conditions. In the Study, BPA is explicitly modeling load growth. Accordingly, we developed this methodology to estimate monthly load variability due to weather that excludes the impact of load growth. Thus, we avoid double-counting the impact of load growth when we calculate monthly load standard deviations for weather conditions from daily load standard deviations.

Q. Why were daily load standard deviations from the 1996 Rate Case Marginal Cost Analysis used in the Study?

A. We used the 1996 MCA because we are not aware of an alternative source of load information from which daily load standard deviations can be computed for both the PNW and California.

Q. Why did you estimate PF load variability using the forecast PF loads that are subject to the load variance charge?

A. We estimated PF load variability using the forecast PF loads that are subject to the load variance charge because BPA is responsible for meeting all incremental changes in loads due to both weather conditions and load growth. *See* Supplemental Load Resource Documentation, WP-07-E-BPA-45A, Section 2.2.1, regarding the forecast amount of PF loads that are subject to the load variance charge.

Section 3.4: California Hydro Generation

Q. Why does BPA include California hydro generation risk in the Study?

A. California hydro generation risk is incorporated into the Study because it affects monthly HLH and LLH spot market electricity prices in California and the Pacific Northwest. These in turn impact BPA's surplus energy revenues and power purchase expenses.

Q. Please describe how California hydro generation risk is quantified.

A. RiskMod randomly selects from 18 years of historical monthly California hydro generation data. Once one of the years is selected for the first year of the rate period, then the following two years of data are referenced in a continuous manner.

Q. Why is California hydro generation data selected in a continuous manner?

A. Selecting hydro generation data in a continuous manner captures the risk associated with various dry, normal, and wet weather patterns over time that are reflected in the 18 years of historical data.

Q. When the end of the 18 years of historical data is reached, why does RiskMod sequentially use monthly California hydro generation data for year one?

A. RiskMod sequentially uses monthly California hydro generation data for year one when the end of the 18 years of historical data is reached so that all 18 years of the data are equally represented in the 3 year water sequences. For example, if hydro generation data for year 18 is selected for FY 2007, then data for years one and two would be used for FY 2008 and FY 2009, respectively.

Section 3.5: California Load

Q. Why is California load risk included in the Study?

A. California load risk is included in the Study because California load variability affects monthly HLH and LLH spot market electricity prices in California and the Pacific Northwest. These price impacts in turn affect Power Services' surplus energy revenues and power purchase expenses.

Q. Please describe how the California load risk is modeled.

A. California load variability is modeled in the California Load Risk Model such that annual load growth variability and monthly load swings due to weather conditions are both accounted for in one California load variability factor. Annual California load growth risk is modeled to simulate various load patterns through time using a mean-reverting, random-walk technique in which load growth variability for the PNW and California are interdependent. *See* discussion of mean-reverting, random-walk technique in Section 3.3.

Q. Why did you model load growth variability for the PNW and California as interdependent?

A. Load growth variability for the PNW and California is modeled as interdependent because there is a strong interrelationship between regional economies and the national economy. This is reflected in the high positive correlation (0.8943) between annual PNW and California loads. *See* Documentation, WP-07-E-BPA-48A, Table 14.

Q. Why were additional annual load variability adjustment factors developed for years one through five (Calendar Years 2005-2009) in the California Load Risk Model?

A. We developed additional annual load variability adjustment factors to more closely match the simulated load growth standard deviations for California to the load growth standard deviations in the historical data.

Q. Why did you use WECC load data for the California/Mexico Power Area from 1987-2004 to calculate the annual load growth deviations for California?

A. We used WECC load data from 1987-2004 to calculate annual load growth deviations for California because a footnote in the WECC publication states that the California/Mexico Power Area data prior to 1987 includes loads in Southern Nevada, which are not included in the California/Mexico Power Area data from 1987-2004. *See* Documentation, WP-07-E-BPA-48A, Table 14.

Q. *Please describe how the variability in monthly loads due to weather conditions was derived.*

A. California monthly load swings due to weather conditions were derived from estimates of daily load standard deviation values for each of the 12 months. The source of these estimates was the 1996 MCA Documentation, WP-96-FS-BPA-04A.

Q. *Why are monthly load standard deviations for weather conditions derived from daily load standard deviations in the Study?*

A. Calculating monthly load standard deviations from historical load data by sorting historical load data for the same month (over a period of years) yields load standard deviations that include both the impact of load growth and weather conditions. In the Study, we are explicitly modeling load growth. Accordingly, we developed this methodology to estimate monthly load variability due to weather that excludes the impact of load growth. Thus, we avoid double-counting the impact of load growth when it calculates monthly load standard deviations for weather conditions from daily load standard deviations.

Q. *Why were daily load standard deviations from the 1996 MCA used in the Study?*

A. We are not aware of an alternative source of data from which updated daily information of this type are available.

Q. *Why was load variability due to weather conditions in the PNW and California modeled as perfectly dependent within the two California regions (southern and northern California) and the three PNW regions (Oregon/Washington, Idaho, and Montana) in AURORA, but independent between the California and PNW regions?*

A. This modeling approach represents a reasonable trade-off, since one would expect a relatively high positive correlation between load swings due to weather within a region and a relatively modest, but still positive, correlation between PNW and California load variability.

Section 3.6: Natural Gas Price

Q. Why is natural gas price risk included in the Study?

A. Natural gas price risk is incorporated into the Study because natural gas price variability affects monthly HLH and LLH spot market electricity prices. These price impacts in turn affect Power Services' surplus energy revenues and power purchase expenses.

Q. Please describe how natural gas price risk is modeled.

A. Natural gas price variability is modeled in the Natural Gas Price Risk Model using a mean-reverting, random-walk technique. The random-walk technique simulates monthly natural gas prices through time where the starting point for simulating the natural gas price in a given month is the monthly natural gas price from the prior month. The mean-reverting technique causes simulated natural gas prices to tend to revert to the forecast natural gas prices as simulated prices move further from forecast prices (either higher or lower). *See* Study, WP-07-E-BPA-48, Section 2.4.5.

Q. Why is a mean-reverting random-walk methodology used for modeling monthly price risk?

A. This methodology provides the flexibility to simulate natural gas prices that can be more volatile in some months than others and that can rise and fall at different rates during the year and across years. This is accomplished through the use of monthly and annual decay parameters, coupled with each month having different month-to-month gas price volatilities. Thus, the flexibility associated with the methodology utilized in the Natural Gas Price Risk Model allows the model to closely calibrate to the attributes of gas price movements in the historical data.

Q. What do you mean when you use the terms "returns" and "volatility" when quantifying natural gas price risk? How are these computed?

A. We derived monthly and annual price volatilities for natural gas prices by computing the standard deviations of all the natural log (ln) price ratio changes from one time period to another. These natural log price ratio changes [ln(price at time t ÷ price at time t-1)] are commonly referred to as "returns" and the standard deviation of these returns is referred to as "volatility" in the technical literature.

Q. You use both the terms "volatility" and "variability" in regard to natural gas price risk. Please explain the differences between these two terms.

A. Volatility has a very specific meaning in the technical literature with these standard deviation values being specified in terms of percentages. For instance, a volatility of 30 percent means that a one standard deviation swing in price is 30 percent of the forecast price. Price variability, as measured by standard deviation, is reflected in dollars and accounts for both the volatility and price level with price variability increasing the higher the volatility and/or the price level.

Q. Why were returns and volatilities computed in this manner?

A. Monthly and annual price volatilities were estimated in this manner so that price movements through time could be modeled using the mean-reverting, random-walk technique.

Q. Why were lognormal probability distributions used for natural gas price risk?

A. We compared the average and median prices for the monthly and annual historical Ignacio, Colorado, price data and found that all the average prices are greater than the median prices. *See* Documentation, WP-07-E-BPA-48A, Table 21. Additional comparisons indicate that the differences between the maximum prices and the median prices are greater than the differences between the minimum prices and the median prices. Asymmetrical differences with these attributes exhibit the shape of lognormal probability distributions with longer tails at higher prices that differ in skewness depending on the size of the differences. Also, the use of lognormal probability distributions for quantifying price risk is well supported in the technical literature (it forms the basis for the Black and Black-Scholes formulas for valuing options). This distribution also reflects that prices cannot go below $0, but that no comparable price limits on the upside exist.

Q. What are the results from the natural gas price risk model?

A. Results from this Natural Gas Price Risk Model on a monthly basis over time are shown in Graph 6 in the Documentation, WP-07-E-BPA-48A, for the 5th, 50th, and 95th percentiles. The monthly natural gas price variability patterns shown in this graph indicate that gas price variability tends to be higher when temperatures are cooler and lower when temperatures are warmer.

Q. Did you make any price level adjustments to the simulated natural gas prices?

A. We made month-specific price level adjustments to the simulated natural gas prices for FY 2007-2009 in order to perfectly align the median monthly simulated gas prices to the monthly prices in the natural gas price forecast.

Q. Why did you make these adjustments based on median prices rather than average simulated prices?

A. We based these adjustments on median prices because we assumed that the natural gas price forecast is a median forecast, where there is a 50 percent probability that natural gas prices could go higher or lower than the forecast. *See* Petty, *et al.*, WP-07-E-BPA-11.

Q. Do the month-specific price level adjustments made to the simulated natural gas prices for FY 2007-2009 alter the price variability?

A. No. These price level adjustments do not alter the price variability because each of these month-specific price level adjustments is applied to all simulated prices for that month.

Q. BPA set minimum and maximum real delivered gas price constraints in the Natural Gas Risk Model at $1.50/MMBtu and $50.00/MMBtu. On what basis did you set values at these levels?

A. The minimum price constraint was set based on reviewing the historical real 2005 dollar prices at Ignacio, Colorado (*see* Documentation, WP-07-E-BPA-48A, Table 21) and adding an additional charge for delivery from Ignacio to Southern California and the maximum price constraint was set such that no simulated prices would be constrained.

Section 3.7: CGS Nuclear Plant Generation

Q. Why is CGS nuclear plant generation risk included in the Study?

A. Nuclear plant generation risk is included in the Study because CGS generation has an impact on the amount of energy that BPA has to buy and sell at variable market prices. This in turn affects BPA's surplus energy revenues and power purchase expenses.

Q. Please describe how the CGS nuclear plant generation risk is modeled.

A. Nuclear plant generation risk is modeled in the CGS Nuclear Plant Risk Model through a process that involves sampling values from uniform probability distributions, substituting the sampled values into a mathematical equation, and simulating variability in CGS output.

Q. Why did you model this risk in this manner?

A. This methodology allows us to calibrate the results from the mathematical equation such that, when all the simulations are run, the expected simulated nuclear plant output is the same as the expected plant output shown in the Supplemental Load Resource Study, WP-07-E-BPA-45. Also, we selected this methodology because the frequency distribution of CGS output produced from the equation is negatively skewed with the median value (the value at the 50th percentile) being higher than average. The shape of the simulated frequency distribution of nuclear plant output appropriately reflects that thermal plants (including CGS) typically operate at output levels higher than average output levels, but the average output is driven down by occasional forced outages in which monthly output can be substantially lower than the typical monthly output.

Q. When modeling the operational risk of CGS, you did not model the risk of expensive repairs or premature decommissioning. Why?

A. We did not need to model these risks in the Study because BPA carries both business interruption and property insurance and pays into a decommissioning fund. The cost for this insurance is included in BPA's revenue requirement. The insurance covers many of the costs associated with prolonged closures due to accidents or expensive repairs. Though not all costs would be covered, the insurance is sufficient to justify not modeling these risks. Therefore, since the premiums for the insurance are in the revenue requirement, we would be double-counting the costs of such outages if we also modeled these risks.

Section 3.8: DSI Benefits

Q. Why is DSI benefit risk included in the Study?

A. This risk factor is incorporated into the Study because there is uncertainty in the amount of DSI benefits that will be paid in FY 2008-2009.

Q. Please describe how DSI benefit risk is modeled.

A. The quantification of this risk reflects the service terms set forth in the BPA Service to DSI Customers for FY 2007-2011, Administrator's Record of Decision (DSI ROD) signed June 30, 2005. *See* Gustafson, *et al.*, WP-07-E-BPA-17. The DSI ROD includes a provision for 560 aMW of financial benefits to be paid to the aluminum company DSIs based on the difference between forward market electricity prices and the lowest cost-based flat PF rate up to a maximum of $12.00/MWh or $58.9 million/year. The quantification of this risk also includes an FPS sale of 17 aMW to the Port Townsend Paper Company via its local utility at a PF-equivalent plus a margin rate. The forward market electricity price risk for a 12-month strip of power was simulated by the Forward Market Price Risk Model. The benefits paid to the aluminum DSI were computed in the DSI Benefit Risk Model, and the service to Port Townsend was accounted for in RevSim.

In the DSI Benefit Risk Model it is assumed that the benefits to the aluminum DSIs (560 aMW) are monetized and that the aluminum DSIs can receive full benefits while adjusting their energy used to as low as 280 aMW to minimize their per unit effective (after BPA payments) electricity price. Benefit computations reflect the following: (1) Complete shutdown of all DSIs at forward market electricity prices of $70.00/MWh or more (*i.e.*, no benefit payments); and (2) no benefit payments for prices below the lowest cost-based flat PF rates. For a discussion of how implementation of the DSI contracts since the WP-07 Final Proposal impacts the quantification of DSI benefits, refer to Section 2.1 above and Section 1.12 of the Documentation, WP-07-E-BPA-48A.

Q. Why are results from the DSI Benefit Risk Model based on the lowest cost-based flat PF rates from a preliminary run of ToolKit?

A. The results from the DSI Benefit Risk Model are computed at the beginning of the iterative rate calculation process, whereas the results from the ToolKit are at the end. Accordingly, it is not possible for the results from the DSI Benefit Risk Model to be based on the final ToolKit run. *See* Documentation, WP-07-E-BPA-48A, Graph 1, regarding the RiskMod risk analysis information flow.

Section 3.9: Wind Project Generation

Q. Why is wind project generation risk included in the Study?

A. This risk factor is incorporated into the Study because changes in the amounts and values of the energy generated by Power Services' portion of Condon, Klondike I and III, Stateline, and Foote Creek I, II, and IV wind projects affect surplus energy revenues and power purchase expenses.

Q. Have any changes been made to the wind project generation risk since the WP-07 Final Proposal?

A. Yes, output from the Klondike III project has been added, beginning in December 2007.

Q. Please briefly describe how this risk is modeled.

A. Wind generation risk is modeled in four risk simulation models, one each for Condon, Klondike (Klondike I and III were combined into a single model), Stateline, and Foote Creek (Foote Creek I, II, and IV wind projects were combined into a single model) based on historical daily wind generation. The risk of the value of the wind generation is based on the difference between the purchase prices specified in each output contract and the spot market electricity prices received for the amount of energy produced, since BPA only pays for the actual energy produced. This financial risk is computed in RevSim.

Q. Why did you combine all Foote Creek wind projects into a single model when modeling wind generation risk?

A. The three Foote Creek projects can be treated as one project because they are all on the same ridgeline, contiguously located, and electrically connected at the same substation.

Wind currents that affect the generation at one of these wind projects will affect the generation at the other wind projects similarly.

Q. *Why did you combine Klondike I and III wind projects into a single model when modeling wind generation risk?*

A. The two Klondike projects can be treated as one project because they both are located on similar rolling terrain, contiguously located, and electrically connected at the same substation. Wind currents that affect the generation at one of these wind projects will affect the generation at the other wind projects similarly.

Q. *Why did you model wind generation risk at Condon, Klondike, Stateline, and Foote Creek separately?*

A. Each of these wind projects are located at different sites and typically experience different daily wind conditions.

Q. *Are there any other differences in the modeling of wind projects?*

A. Yes. Unlike all the other wind generation risk models in which the averages of the simulated monthly generation outcomes for each project equals the expected monthly generation included in the Supplemental Load Resource Study, WP-07- E-BPA-45, the averages of the combined simulated monthly generation for Klondike I and III in the Klondike Wind Project Risk Model are slightly different than the values in the Load Resource Study. In the Supplemental Load Resource Study, monthly Klondike III output was derived from historical generation data from Klondike II. In the Klondike Wind Project Risk Model, Klondike I and III wind generation risk was jointly derived based on historical wind generation data for Klondike I. This difference results in annual average wind generation simulated by the Klondike Wind Project Risk Model being 0.5 aMW higher than in the Supplemental Load Resource Study.

Q. How did you derive monthly wind generation risk?

A. We derived monthly wind generation risk by sampling from cumulative probability distributions of historical daily wind generation for each project.

Q. What is the basis for deriving monthly wind generation in this manner?

A. The daily wind generation from one day to the next day was modeled independently based on the erratic daily generation amounts from one day to the next exhibited in the historical data. Given this phenomenon, monthly wind generation was derived in the following manner: (1) sample the daily wind generation values from the cumulative probability distributions for each day in a given month (*i.e.*, 31 days for January); (2) sum the daily wind generation values for all days in a given month; and (3) divide the monthly sum by the number of days in that particular month.

Q. Why did you model the daily wind generation risk using cumulative probability distributions?

A. There are three reasons for using the cumulative probability distribution. First, there were adequate historical data to develop many data points on these probability distributions, since the probability distributions were developed from three years of daily data (on average, about 90 observations) with generation values varying over a wide range of output levels. Second the cumulative probability distribution allows the modeler to replicate the risk represented in the historical data, with the additional benefit that the expected/average simulated monthly generation values equal the generation values in the Load Resource Study. *See* Supplemental Load Resource Study, WP-07-E-BPA-45. Finally, using this probability distribution obviates the need for the modeler to specify what functional form (such as a Weibull probability distribution) best represents the phenomena being modeled. *See* Documentation, WP-07-E-BPA-48A, Section 1.13.

Section 3.10: Power Services Transmission and Ancillary Services Expense

Q. Why is the Power Services transmission and ancillary services expense risk included in the Study?

A. The Power Services transmission and ancillary services expense risk is incorporated into the Study because changes in Power Services transmission and ancillary services expenses affect Power Services expense levels directly.

Q. Please describe how this risk is modeled.

A. The Power Services transmission and ancillary services expense risk is modeled in the Transmission Expense Risk Model and is based on comparisons between monthly firm transmission capacity that Power Services has under contract, firm contract sales, and variability in surplus energy sales estimated by RevSim. Expense risk computations reflect how transmission and ancillary services expenses vary from the cost of the fixed, take-or-pay, firm transmission capacity that the Power Services has under contract, which must be paid regardless of whether or not it is used. The methodology used in the Transmission Expense Model is consistent with the methodology documented in BPA's Power Function Review February 1, 2005 Technical Workshop on the Transmission Acquisition Program.

Q. Why are there $70 million in transmission expenses when there are no surplus energy sales?

A. Power Services transmission and ancillary services expenses do not fall below $70 million/year, regardless of the amount of surplus energy sales, because the Power Services must pay for the take-or-pay firm transmission capacity it has under contract. This $70 million/year figure does not include the cost of ancillary services for any surplus energy sales, since these charges are assessed depending on the actual amount of transmission used. As explained above this value will be revised in the Final Supplemental Proposal.

Q. *Why do Power Services transmission and ancillary services expenses increase at varying rates as the amount of surplus energy sold increases?*

A. Power Services' firm transmission capacity can accommodate approximately 1000 aMW of surplus energy sales. Only ancillary services expenses vary on the first increment of secondary energy sales (up to about 1000 aMW) while both transmission expenses and ancillary service expenses vary for surplus energy sales above this amount.

Section 3.11: Forward Market Electricity Price

Q. *Why is forward market electricity price risk included in the Study?*

A. Forward market electricity price risk is included in the Study because changes in forward market prices affect the amount of DSI benefits. These benefits in turn affect Power Services' expense levels.

Q. *Please describe what forward market electricity price curves are.*

A. Forward market electricity price curves are estimates at a point in time of what electricity prices will be over a period of time in the future.

Q. *Please describe how this risk is modeled.*

A. Forward market electricity price curves change as time progresses, often in response to whether actual spot market prices are higher or lower than the forward market price at the beginning of the spot month for that month. Based on this interrelationship, we designed the Forward Market Price Risk Model to estimate forward market electricity price curve movements through time that are consistent with the spot market electricity price movements estimated by AURORA. *See* Supplemental Market Price Forecast Study, WP-07-E-BPA-47. This task was accomplished in the following steps:

(1) derive, through regression analysis on historical daily Mid-C price data, a series of regression equations that quantifies the relationships between the changes in spot market prices and forward market prices over a 35-month period; and (2) use these regression equations to simulate, on a monthly basis, how the forward market price curve changes from the forward market price curve for the prior month based on the difference between the actual spot market price (estimated by AURORA) and the forward market price at the beginning of the spot month for the spot month.

Q. What assumption are you making in the Forward Market Price Risk Model regarding the relationship between the expected monthly spot market price and the forward market price for the spot month at the beginning of the month?

A. We are assuming the forward market price at the beginning of the spot month for that month is the same as the expected spot market price for that month. Otherwise, arbitrage opportunities would exist that would likely be exploited.

Q. Why did you design the Forward Market Price Risk Model to estimate forward market electricity price curve movements through time that are consistent with the spot market electricity price movements estimated by AURORA?

A. This approach accounts for the dependency between the spot market electricity prices used to calculate surplus energy revenues and power purchase expenses and the forward market electricity prices for a 12-month strip of power used to DSI benefits.

Q. Why did you specify a minimum monthly forward market price for the Forward Market Price Risk Model?

A. We specified a minimum monthly forward market price in the Forward Market Price Risk Model so that no simulated monthly forward market price would fall below $5.00/MWh.

Q. *Why did you make this assumption?*

A. We made this assumption based on observing that AURORA monthly spot market prices seldom go below $5.00/MWh.

Section 3.12: Section 4(h)(10)(C) Credit

Q. *Why is the section 4(h)(10)(C) risk included in the Study?*

A. The section 4(h)(10)(C) risk is incorporated into the Study because there is variability in the amount of section 4(h)(10)(C) credits that BPA is allowed to credit against its annual Treasury payment. *See* Supplemental Revenue Requirement Study, WP-07-E-BPA-46, Section 5.2, for a discussion of section 4(h)(10)(C) credits.

Q. *Please briefly describe how this risk is modeled.*

A. The costs of the operational impacts are calculated for each of the 50-water years in RevSim for FY 2008-2009 by multiplying spot market electricity prices from AURORA by the amount of power purchases (in average megawatts) that qualify for section 4(h)(10)(C) credits. These variable operational credits are combined with deterministic expenses and capital costs associated with fish and wildlife mitigation measures. *See* Documentation, WP-07-E-BPA-48A, Section 1.5.5.

Q. *Were any changes made in determining the costs of the operational impacts since completion of the WP-07 Final Proposal?*

A. Yes, since completion of the WP-07 Final Proposal, the assignment of monthly hours to heavy load hours (HLH) and light load hours (LLH) in RevSim has been revised to agree with the Supplemental Load Resource Study, WP-07-E-BPA-45. These revisions result in a slightly different average price, which is computed from the monthly HLH and LLH prices from AURORA. The result is a small difference to the operational costs computed when applying the average monthly price to the power purchases that qualify for section 4(h)(10)(C) credits.

Section 4: Development of the Net Secondary Energy Revenue Forecast

Q. What is a net secondary energy revenue forecast?

A. A net secondary energy revenue forecast consists of a forecast of surplus energy sales revenues and short-term power purchase expenses. BPA uses RiskMod to calculate the net secondary revenue forecast.

BPA obtains its primary revenues from the sale of hydroelectric power and other resources to customers to meet firm loads. BPA plans its resources to meet firm load obligations under *critical* water conditions on an annual average, not monthly, basis. Critical water conditions are characteristic of the nearly worst water supply conditions in the existing 50-water year historical record (October 1928 through September 1978). Secondary revenues are derived from the sale of power in excess of BPA's firm load obligations. Even though BPA plans to meet its firm loads on an annual average basis, variations in loads and resources among months and between heavy and light load hour periods may require short-term purchases to meet firm loads. These short-term purchases (also known as balancing purchases) are included in the net secondary revenue forecast.

Q. Does BPA plan to make any power purchases to meet its firm load obligations under critical water conditions for FY 2009?

A. Yes. BPA expects to purchase 341 aMW in FY 2009 in order to meet firm loads. *See* Misley, *et al.*, WP-07-E-BPA-64.

Q. What is the forecast price for these projected purchases in FY 2009?

A. The weighted annual average purchase price for critical water (1937) for FY 2009 was used to estimate the cost of these purchases. For FY 2009, this price was $61.42/MWh.

Q. How is the net secondary revenue forecast for the Supplemental Proposal used?

A. The calculation used to set rates to recover costs subtracts the forecast of net secondary revenues (net of short-term purchase expenses) from forecast Power Services expenses. The estimate of net secondary revenue has a direct and significant impact on the magnitude of the rate.

Q. Were forecasts of net secondary revenue made for years beyond FY 2009?

A. Yes. Forecasts of net secondary revenue were made for FY 2010-2013 for use in the section 7(b)(2) rate test. *See* Keep, *et al.*, WP-07-E-BPA-68.

Q. What prices were used to develop the forecast of net secondary revenue for FY 2010-2013?

A. Prices from FY 2009 were escalated by 2.5 percent per year.

Q. Where are secondary revenues for FY 2010-2013 documented?

A. Secondary revenues for FY 2010-2013 are documented in the Documentation, WP-07-E-BPA-48A, Table 13A.

Q. Please describe the general approach used in developing BPA's net secondary revenue forecast.

A. BPA's net secondary revenue forecast is a product of two components: (1) a forecast of surplus market sales and purchase amounts, and (2) a forecast of expected prices for those sales or purchases. Secondary market sales are made when generation exceeds BPA's firm load obligations. For the current rate proposal, these sales are broken out by month and by LLH and HLH periods. In addition, BPA purchases power when it does not have enough energy to meet its firm load obligations.

The forecast of prices at which BPA would be selling surplus energy and purchasing to meet short-term deficits is provided by AURORA. AURORA is used to develop monthly LLH and HLH spot market prices. The prices are applied to the corresponding monthly LLH and HLH sales and purchase amounts to calculate sales revenues and purchase expenses. *See* Supplemental Market Price Forecast Study, WP-07-E-BPA-47, for additional information on how AURORA is used to develop price forecasts.

Q. How did you estimate secondary market surpluses and deficits?

A. Secondary market surpluses and deficits were generated through a simulation process. To represent the uncertainty in forecasting surplus market sales and purchase amounts due to the variability in hydro generation, we forecast generation from the Federal Columbia River Power System using the 50-water year historical water record. For each monthly LLH and HLH period, Federal firm loads are subtracted from total Federal resources. Positive values indicate an amount of surplus energy that can be sold and negative values indicate a deficit or an amount of power that needs to be purchased.

Using the 50-water year historical record provides a distribution of surplus and deficit values. This distribution is comprised of a separate value for LLH and HLH for each month under 50 different water conditions. Information about BPA's firm load obligations, hydro generation derived from the 50-water year historical record and other Federal resources can be found in the Supplemental Load Resource Study, WP-07-E-BPA-45.

Q. How are net secondary revenues estimated?

A. Revenues from the secondary market sales were estimated for LLH and HLH for each month and water condition by multiplying the surplus energy forecast by the spot market electricity price generated by AURORA. The resulting LLH and HLH revenues were summed to get a monthly total. Monthly totals were summed to get an annual total. The resulting surplus energy sales revenues along with monthly energy sales and prices for

FY 2009 can be found in the Supplemental Wholesale Power Rate Development Study (WPRDS) Documentation, WP-07-E-BPA-049A, Table 3.8.1.

Q. *How did you estimate power purchase amounts?*

A. Power purchase amounts are equal to the deficits calculated in the above discussion about calculating surpluses and deficits.

Q. *How did you estimate purchased power expenses?*

A. Purchased power expenses were estimated using the same process used to estimate surplus energy revenues. Purchased power expenses were estimated by multiplying the LLH or HLH spot market electricity price in a particular month and a particular water condition by the corresponding purchased power quantity. The same process was followed for all water conditions and months where purchases were necessary. The LLH and HLH purchases for each month were summed to provide the monthly totals, and summed again to provide the annual total. The expected value of the distribution of annual values is reported as the total purchased power expense estimate. The resulting power purchase expenses along with monthly purchase amounts and prices for FY 2009 can be found in the Supplemental WPRDS Documentation, WP-07-E-BPA-049A, Table 3.8.2.

Q. *Which model calculates the net secondary revenue forecast?*

A. The net secondary revenue forecast is calculated by RiskMod. *See* Study, WP-07-E-BPA-48, Section 2.4.12.

Q. *How much secondary power are you projecting BPA to market in FY 2009?*

A. In FY 2009, we expect BPA to market approximately 1,730 aMW of secondary hydroelectric generation net of power purchases, *i.e.*, total secondary sales less power purchases.

Q. Are these 1,730 aMW of forecast sales net of Slice?

A. Yes. Secondary energy marketed by Slice customers is not included in this figure.

Section 5: Non-Operating Risk Model

Q. What is the Non-Operating Risk Model?

A. The Non-Operating Risk Model, or NORM, is a model that was developed to quantify risks other than operational risks in the rate-setting process. Like RiskMod, NORM uses a simulation methodology to create a set of alternative outcomes. The frequency distribution of the output data reflects BPA's current estimate of the probabilities of future events that could affect BPA's non-operating expense levels. The outputs from NORM and RiskMod are used in the ToolKit model. NORM is written in Excel, with the @RISK add-in program. The output is saved into a standard Excel file.

Q. What are operational risks?

A. In general, operating risks include variations in prices, loads, and generation resource capability related to operating the hydro system. Most of these risks are modeled in RiskMod. NORM models the non-operating risks for the Study.

Q. What changes have been made to NORM since the WP-07 Final Proposal?

A. For the Supplemental Proposal, we have made four major changes to NORM. First, NORM is modeling only the uncertainty around FY 2008-2009 costs and revenues. Second, we have updated some cost estimates for FY 2008-2009. Third, we have revised some probability distributions to take into account FY 2007 actual results. And finally, certain risks are no longer being modeled in NORM. Each of these changes is described more fully below.

Q. *How did you revise the cost estimates used in the Supplemental Proposal?*

A. FY 2007 was removed for the Supplemental Proposal. FY 2008 cost estimates were revised to be consistent with BPA's First Quarter Review. FY 2009 cost estimates were revised to be consistent with the revised FY 2009 revenue requirement. *See* Homenick and Lennox, WP-07-E-BPA-65.

Q. *What risks are reflected in NORM for the Supplemental Proposal?*

A. NORM models the risks around certain components of the revenue requirement. These include non-operating costs which are the responsibility of the generation function. Specifically for the Supplemental Proposal, NORM models uncertainties in the following cost categories:

- Columbia Generating Station O&M
- Corps of Engineers (COE) & Bureau O&M
- Colville & Spokane Settlement
- Energy Efficiency Capital
- Power Services Purchases of Transmission & Ancillary Services
- Corporate G&A
- Power Services Internal Operations
- Fish & Wildlife O&M
- Lower Snake Hatcheries
- Fish & Wildlife Capital Expenditures
- COE & Bureau Capital Expenditures
- Columbia River Fish Mitigation Project
- Capital Equipment
- Renewables Facilitation Expense

In addition, the following key economic risk drivers are modeled:

- Interest Rates
- Inflation

Only the risks that affect Power Services associated with the transmission function are modeled in NORM or RiskMod for the Supplemental Proposal. For a description of how transmission risks are modeled. *See* Study, WP-07-E-BPA-48, Section 2.5.3.5.

Q. *What risks are not being modeled for the Supplemental Proposal?*

A. The risks around the following cost and revenue items are not being modeled for the Supplemental Proposal:

- Consumer-owned Utilities Residential Exchange costs
- Purchases of Reserves and other Services from Transmission Services
- CGS capital costs
- Revenues from within-the-band Generation Supplied Reactive power sold to Transmission Services

Q. *Why are the risks around these cost and revenue items no longer being modeled in NORM for the Supplemental Proposal?*

A. Because BPA is currently working with regional stakeholders to develop a new REP in this and a separate process, REP costs are not being modeled in NORM for the Supplemental Proposal. At this time, BPA does not know whether any consumer-owned utilities (COUs) will be participating in the REP during FY 2009. However, under the current ASC Methodology proposal, any utilities wishing to participate in the REP during FY 2009 must notify BPA no later than February 22, 2008. The ASC's of any participating COUs will be determined prior to the final Supplemental Proposal. But since the net benefit levels for COUs are not subject to the Lookback, BPA will examine the potential exchange load variability and related net benefit level variability in the final

Supplemental Proposal for any COUs that decide to participate in the REP during FY 2009.

For Reserve and Other Services in the final Supplemental Proposal, NORM modeled the uncertainty around future Transmission Services price increases for FY 2008-2009. Because transmission rates for FY 2008-2009 were established in Transmission Services' recent rate case, NORM is no longer modeling this uncertainty for the Supplemental Proposal.

Since the WP-07 Final Proposal, Energy Northwest (EN) has revised its estimates for CGS capital investments. The revised estimates include replacement of the CGS condenser tubes, which was the major source of uncertainty for the WP-07 Final Proposal. These revised estimates have been included in NORM for the Supplemental Proposal. Also, BPA has already completed the FY 2008 financing for CGS capital expenditures, removing the interest rate uncertainty for FY 2008. For these reasons, NORM is not modeling uncertainty around CGS capital expenditures for the Supplemental Proposal.

Finally, for the WP-07 Final Proposal, NORM modeled the uncertainty around the level of payments that Power Services would receive for Generation Supplied Reactive services provided to Transmission Services for FY 2008 and FY 2009. Because Power Services is no longer receiving revenues from Transmission Services for within-the-band reactive power services, this uncertainty is not being modeled in NORM for the Supplemental Proposal.

Q. Why was this particular set of non-operating risks chosen?

A. We chose to model NORM uncertainties that met one or more of the following three criteria: the component (1) has a large range of uncertainty; (2) has specific uncertainties that are readily quantifiable, such as interest rate uncertainty; or (3) is a specific Power

Function Review (PFR) cost saving recommendation and there is some uncertainty whether it can be achieved.

Q. *Why is there a need to address non-operating risks in the Supplemental Proposal?*

A. As we were preparing for the WP-02 rate case, it was clear that there were important non-operating risks that were not being captured in BPA's operating risk modeling. We determined it would understate the total financial uncertainty if these risks were not modeled. To meet its fiduciary responsibility to the Treasury and others, we prepared NORM to incorporate these uncertainties. Since we still face important non-operating risks, we continue to use NORM in our rate case modeling; we did so in the WP-07 rate proceeding, and are doing so again in this Supplemental Proposal.

Q. *How does NORM work?*

A. For the significant non-operating risks we identified above, we developed a distribution of possible outcomes and associated probabilities. Developing the distribution required that we estimate the probability that the costs or revenues would deviate from what was included in the revenue requirement, and by how much.

Q. *How was the information regarding non-operating risk gathered?*

A. To obtain the data used to develop the probability distributions, we interviewed the subject matter experts (SME) for each capital and expense item modeled. Prior to each interview, the SME was sent a set of questions to think about regarding the risks surrounding the cost estimates included in the final PFR. During each interview, the SME was asked for his or her assessment of the risks concerning the cost estimates including the possible range of outcomes and the associated probabilities of occurrence. Each of the subject matter experts were interviewed regarding the following:

- Purpose and function of the cost category
- Budget level and key drivers

- Expected value
- Most likely value if it differed from the expected value
- Factors that could influence the expected value and distribution

Q. *How were the risk parameters and distributions developed?*

A. Based on the results of the interviews, we developed the probabilities and deviations for NORM.

Q. *What factors contributed to the type and shape of the cost distributions used in NORM?*

A. The type and shape of the cost distribution depended on two key factors:

(1) Identifying the drivers that influence the cost category, and

(2) BPA's ability to quantify the uncertainty associated with these drivers.

Given the diversity of the cost categories and risk factors, we utilized a number of different risk approaches. *See* Study, WP-07-E-BPA-48, Section 2.5.2.

Q. *How were the probability distributions revised using FY 2007 actual values?*

A. If the FY 2007 actual value fell outside the probability distribution established for that cost or revenue item in the WP-07 Final Proposal, we revised the distributions for both FY 2008 and FY 2009. First, the FY 2007 value was inflated by 3 percent per year. The inflated value was used to establish new minimum values for the FY 2008-2009 probability distributions if the FY 2007 actual value was below the minimum of the FY 2007 probability distribution, or to establish new maximum values if the FY 2007 actual value was above the maximum value of the FY 2007 probability distribution.

Q. *How will NORM be updated for the final Supplemental Proposal?*

A. Generally, we will update the costs and revenues for FY 2008 to be consistent with BPA's most recent Quarterly Review. FY 2009 costs and revenues will be updated to be consistent with any changes made to the FY 2009 revenue requirement resulting from the cost review processes. *See* Homenick and Lennox, WP-07-E-BPA-65. We may also model uncertainty around additional cost or revenue items that emerge as a result of this rate proceeding.

Section 6: Accrual-to-Cash

Q. What is the purpose of the Accrual-to-Cash (ATC) adjustment?

A. The ATC adjustment makes the necessary changes to convert the net revenue scenarios (accruals) provided by RiskMod and NORM into the equivalent reserves (cash) value needed by ToolKit to calculate TPP.

Q. Is this adjustment new for the Supplemental Proposal?

A. No. The WP-07 Final Proposal included the current ATC adjustment.

Q. Why do net revenues and cash differ?

A. For ToolKit and TPP purposes, there are four major factors that cause cash and net revenues to differ. First, some revenues and expenses accrued and included in net revenues do not affect cash. These include the depreciation and amortization of Power Services' physical and non-physical assets and the interest adjustments shown on lines 1 and 2 of the ATC Table, Table 2, of the Study, WP-07-E-BPA-48, Section 2.5.3.11. Second, there are timing differences between when certain accrued revenue and expense items are reflected in the income statement, and when the associated cash is received or paid. These items include the EN prepaid expense adjustments (Line 3 of the ATC Table), any mismatch between the amount collected through rates for Residential Exchange forecast expense and the associated cash disbursement, the Slice True-Up, and various terminated purchase and sales contract amounts and other miscellaneous items included in the "All Other" category on line 4 of the ATC Table. Third, there are various sources and uses of cash associated with BPA's capital spending program that do not flow through the income statement, including both Planned Advanced

Amortization of Federal Debt and Scheduled Federal Debt Amortization, lines 8 and 10 of the ATC Table. Fourth, there are other items of cash flow that also do not affect income. These include customer advances for work to be performed, such as the Energy Efficiency projects; funds held by BPA for other agencies pending termination of certain agreements; and customer credit deposits held in lieu of other credit enhancement instruments. These are also included on line 4 of the ATC Table.

Q. What assumptions, if any, have been made regarding the collection and disbursement of cash through the proposed Interim Agreements and Standstill Payment Agreements?

A. Regarding cash disbursements made to the IOUs and the COUs due to the interim agreements, at the time the ATC analysis was completed we estimated that the cash disbursements for FY 2008 would be about $3.4 million less than the cash collected through rates during FY 2008. We will update this number for the Final Supplemental Proposal, based on the total payout made to those COUs and IOUs that sign the interim agreements. No assumption has been made in the modeling for this Initial Supplemental Proposal about how the disbursements will be divided between COUs and IOUs because such an assumption is not necessary for this analysis.

Q. What are the interest adjustments on line 2 of the ATC Table?

A. These reflect the amortization of the Capitalization Adjustment which resulted from the restructuring of BPA's Federal appropriated debt in The Bonneville Appropriations Refinancing Act, implemented October 1, 1997. *See* Supplemental Revenue Requirement Study, WP-07-E-BPA-46, Section 5.1.3. For Power Services' portion of the refinanced debt, part of the Capitalization Adjustment is amortized (written off) annually and recognized on the income statement as a non-cash reduction in interest expense each year. Because this transaction has no cash impact, Power Services' actual cash obligation to Treasury is not reduced. Therefore, Power Services' actual interest payment is higher than its accrued interest expense by the amortized amount of the Capitalization Adjustment. The interest adjustments also include amortization of capitalized bond premiums.

Q. Please describe the results of the ATC calculations.

A. Lines 1 through 4, and lines 6 through 8, of the ATC Table sum to the amounts shown on lines 5 and 9 respectively. Lines 5, 9, 10 and 11 are then added to get the ATC adjustment shown on line 12.

Q. What transmission data, if any, are included in the ATC and TPP calculations?

A. No revenue and expense data for Transmission Services has been included. There are some transmission expenses that Power Services accrues that are included.

Q. What changes might be made in the final Supplemental Proposal with respect to the accrual to cash adjustments?

A. The most likely adjustments include incorporating a new EN budget for EN's FY 2009, which starts July 1, 2008, and which may also include any refinancing of EN debt service. There could be some updates to EN's budget for its FY 2010. There could also be some change to Power Services non-cash expense estimates based on changes to its expected capital spending. Finally, adjustments will also be made to capture changes in expenses, revenues, and cash resulting from transactions entered into between the time of this Supplemental Proposal and the time of the final Supplemental Proposal where the associated stream of accrued revenues and/or expenses would differ from the stream of cash payments or receipts, such as the settlement or termination of any power purchase or sales contracts.

Q. How is the uncertainty in the ATC modeled in the risk study?

A. Not all changes in expense result in a similar change in cash. As a result, ATC is being modeled probabilistically in NORM for this rate case. NORM uses the deterministic

ATC Table referred to above as its starting point, but replaces the deterministic value with the new value for each scenario. *See* Study, WP-07-E-BPA-48, Section 2.5.3.11.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY of

BYRON G. KEEP, RAYMOND D. BLIVEN, PAUL A. BRODIE,

WILLIAM J. DOUBLEDAY and MICHAEL MACE

Witnesses for Bonneville Power Administration

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TESTIMONY of

BYRON G. KEEP, RAYMOND D. BLIVEN, PAUL A. BRODIE,

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Witnesses for Bonneville Power Administration

SUBJECT: FY 2009 SECTION 7(b)(2) RATE TEST STUDY

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is William J. Doubleday. My qualifications are stated in WP-07-Q-BPA-11.

A. My name is Raymond D. Bliven. My qualifications are stated in WP-07-Q-BPA-58.

A. My name is Paul A. Brodie. My qualifications are stated in WP-07-Q-BPA-07.

A. My name is Byron G. Keep. My qualifications are stated in WP-07-Q-BPA-22.

A. My name is Michael Mace. My qualifications are stated in WP-07-Q-BPA-33.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to sponsor BPA's Supplemental Section 7(b)(2) Rate Test Study (Study), WP-07-E-BPA-50, and Supplemental Section 7(b)(2) Rate Test Documentation (Documentation), WP-07-E-BPA-50A. In addition, we are sponsoring BPA's proposed *Section 7(b)(2) Implementation Methodology* (*Proposed Methodology*), Study, WP-07-E-BPA-50, Attachment B. A companion document to the *Proposed Methodology*, the *Section 7(b)(2) Legal Interpretation* (*Proposed Interpretation*), is also being proposed by BPA. While this panel does not sponsor the *Proposed Interpretation* because it is legal opinion, we refer to this document extensively. Therefore, we have attached it to the Study. *See* Study, WP-07-E-BPA-50, Attachment A.

Q. Please summarize your testimony and its organization.

A. This testimony will discuss the implementation of the rate test established by section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act

(Northwest Power Act). Section 1 outlines the purpose of this testimony. Section 2 summarizes the section 7(b)(2) rate test and outlines proposed changes to the test. Section 3 describes the *Proposed Methodology* and discusses the proposed changes. Section 4 discusses the determination of the test period for the 7(b)(2) rate test. Section 5 discusses the financing benefits analysis performed by BPA's financial advisor, Public Financial Management (PFM), and the application of that analysis to the rate test. This is the only section on which Mr. Mace is testifying. Section 6 discusses resource acquisitions in the 7(b)(2) Case. Section 7 discusses the identification of non-dedicated resources in the 7(b)(2) Case. Section 8 discusses the treatment of conservation in the rate test. Section 9 discusses the absence of reserve benefits from curtailment of direct service industrial customer (DSI) loads. Section 10 discusses the changes in the model used to perform the rate test. Finally, Section 11 summarizes the results of the rate test.

Section 2: The 7(b)(2) Rate Test

Q. What is the 7(b)(2) rate test?

A. Section 7(b)(2) of the Northwest Power Act requires that after July 1, 1985, BPA will perform a rate test to ensure that the projected amounts to be charged for firm power for the combined general requirements of BPA's PF Preference customers may not exceed, in total, an amount equal to the power costs to such customers calculated using five specific assumptions that remove certain effects of the Northwest Power Act.

Q. How was the 7(b)(2) rate test performed for the current WP-07 Supplemental Proposal?

A. The rate test involves the projection and comparison of two sets of wholesale power rates for the general requirements of BPA's public body, cooperative, and Federal agency customers (7(b)(2) Customers). The two sets of rates are: (1) a set for the rate filing period (FY 2009) and the ensuing 4 years (FY 2010-2013) before section 7(b)(2) is incorporated (Program Case rates); and (2) a set for the same period taking into account the five assumptions listed in section 7(b)(2) (7(b)(2) Case rates). The 7(b)(2) Case rates are modeled in the same manner as the Program Case rates except for the five assumptions listed in section 7(b)(2). The five assumptions used to model the 7(b)(2) Case are:

(1) Within or adjacent DSI loads are transferred to 7(b)(2) Customers at the start of the 7(b)(2) rate test period; the remaining DSI loads are transferred to non-7(b)(2) Customers and are not considered in the 7(b)(2) Case.

(2) 7(b)(2) Customers are served with Federal Base System (FBS) resources not obligated under contracts existing as of the effective date of the Northwest Power Act.

(3) No section 5(c) Residential Exchange Program (REP) takes place.

(4) Additional resources of three specified types serve the remaining loads of 7(b)(2) Customers when FBS resources are exhausted. These resources are outlined in the 7(b)(2)(D) resource stack.

(5) The reserve benefits acquired under provisions of the Northwest Power Act are not available in the 7(b)(2) Case. Financing benefits to 7(b)(2) Customers under provisions of the Northwest Power Act are not available in the 7(b)(2) Case.

The 7(b)(2) Case rates will reflect these increased costs to the 7(b)(2) Customers. For a discussion of the development of the Program and 7(b)(2) Case rates, *see generally* Study, WP-07-E-BPA-50, and Documentation, WP-07-E-BPA-50A.

Q. What was done after the two sets of rates were developed?

A. Certain specified costs allocated pursuant to section 7(g) of the Northwest Power Act were subtracted from the Program Case rates. Next, the nominal rate for each year was discounted to the beginning of the test year of the relevant rate case, in this case FY 2009. The discounted Program Case rates were averaged, as were the discounted 7(b)(2) Case rates. Both averages were rounded to the nearest tenth of a mill for comparison. Because the average Program Case rate was higher than the average 7(b)(2) Case rate, the rate test triggered by 5.2 mills per kilowatthour.

Q. Was the 7(b)(2) rate test conducted in generally the same manner for the Supplemental Proposal as it was for the WP-07 Final Proposal?

A. Yes. BPA used an updated computer model to conduct the test, which was used for the WP-07 Final Proposal. This model is discussed in greater detail in Section 10.

Section 3: Section 7(b)(2) Implementation Methodology

Q. What is the Section 7(b)(2) Implementation Methodology*?*

A. The *Proposed Methodology* is included in the Study, WP-07-E-BPA-50, Attachment B. The *Methodology* is a document that guides BPA in performing the 7(b)(2) rate test. It sets forth the methodologies to be used in preparing the necessary inputs and describes the assumptions to be used in developing the rates to be compared in the rate test.

Q. When was the Section 7(b)(2) Implementation Methodology *first adopted?*

A. The first *Implementation Methodology* was developed in a section 7(i) rate proceeding in 1984. A Record of Decision was published adopting the *Methodology* on August 17, 1984. *See* Section 7(b)(2) Implementation Methodology ROD, b-2-84-F-02. The *Methodology* was then incorporated into BPA's 1985 wholesale rate adjustment proceeding and filed with the Federal Energy Regulatory Commission with the 1985 rate case record. Subsequent to the adoption of the *Methodology*, a number of rate test issues have been raised in various rate proceedings.

Q. Why is BPA now proposing a new Section 7(b)(2) Implementation Methodology*?*

A. For three reasons. First, there have been changes to BPA's *7(b)(2) Legal Interpretation*. *See* Study, WP-07-E-BPA-50, Attachment A. These changes require changes to the *Methodology*. Second, it has been over 20 years since the *Methodology* was adopted. A number of rate test issues have been raised in subsequent rate proceedings that tested the decisions made in the initial *Methodology*. Based on these decisions and the experience BPA has gained in performing the rate test, BPA seeks to provide more clarity regarding the assumptions used in the rate test for this rate proposal and for the years to come. Third, some of the language of the 1984 *Methodology* was written in a manner more applicable to the use of the Supply Pricing Model (SPM), the first computer model used for the rate test. The SPM has now been replaced with the Rate Analysis Model (RAM). Some of the language changes were made to make the modeling language more generic.

Q. Does BPA propose to make any major changes to the Methodology*?*

A. Yes. The determination of which resources are dedicated to load pursuant to section 5(b) of the Northwest Power Act has been revised. The treatment of acquired conservation resources also has been clarified. The extent to which natural consequences are recognized in the 7(b)(2) Case has been limited to now exclude elasticity of demand. Also, a provision regarding the treatment of REP settlement costs has been included.

Q. How is the Proposed Methodology *organized?*

A. The *Proposed Methodology* begins with an introduction, definitions and a summary of the *Proposed Interpretation*. The definitions included in the *Proposed Methodology* are the same as in the *Proposed Interpretation*. Next is a description of the inputs and assumptions for the Program Case, followed by a description of the inputs and assumptions for the 7(b)(2) Case. This is followed by sections describing computer modeling, the comparison of the rates from the two Cases, and the calculation of the protection amount.

Q. Please describe BPA's proposed changes in the first three sections.

A. The changes to the introduction are minor and intended to add clarity. Several new definitions are included to provide clarity and to be to be consistent with the definitions in the *Proposed Interpretation*. The summary of the Legal Interpretation was replaced to conform to the *Proposed Interpretation*.

Q. What changes were made to the Program Case section of the Methodology*?*

A. The Program Case section was expanded to mirror the topics in the 7(b)(2) Case section and to provide more clarity regarding the use of rate case assumptions in the Program Case.

Q. What changes were made to the 7(b)(2) Case section of the Methodology*?*

A. The 7(b)(2) Case section was revised to reflect changes in the *Proposed Interpretation* regarding conservation and non-dedicated resources in the 7(b)(2)(D) resource stack. The subsection on the load forecast clarifies how conservation is used to adjust the load forecast. The subsection on DSI loads removes elasticity of demand as a natural consequence. The subsection on resources has updated the references to pre-Act obligations. A new subsection on revenue requirements is included to clarify the differences between the Program Case and the 7(b)(2) Case. The subsection on surplus sales clarifies the prices assumed for the sale of surplus FBS in the 7(b)(2) Case. The subsection on financing benefits was changed to clarify that the financing differences apply to only 7(b)(2) Customer resources. It also includes language that would allow different financing assumptions for conservation resources should conditions warrant. Finally, the subsection on reserve benefits clarifies when the application of reserves is appropriate.

Q. Were any further changes made?

A. Yes. The section of the *Methodology* discussing computer models removes outdated language specific to the SPM. Minor language changes to the rate comparison section and conclusion are intended only for clarity.

Q. What will become of the Proposed Methodology *upon conclusion of the Supplemental Proceeding?*

A. The *Proposed Methodology*, as it may be revised in this proceeding, will guide future rate tests until modified in a subsequent section 7(i) proceeding.

Section 4: Test Period

Q. Please describe the determination of the test period for the 7(b)(2) rate test for the Supplemental Proposal.

A. The Supplemental Proposal uses a one-year rate period. The *Proposed Methodology* states that the test period will consist of the test year for the relevant rate case plus the ensuing four years. In developing the rates in the Supplemental Proposal, BPA is using FY 2009 as the test period. Therefore, because the test period is one year, we use that year (FY 2009) plus the ensuing four years (FY 2010-2013) as the 7(b)(2) rate test period.

Section 5: Financing Analysis

Q. What is the financing analysis?

A. Section 7(b)(2)(E) of the Northwest Power Act directs the Administrator to assume for purposes of the rate test that quantifiable monetary savings resulting from reduced public body and cooperative financing costs were not achieved. The financing analysis determines resource financing costs associated with different resource types identified in section 7(b)(2) of the Northwest Power Act for 7(b)(2) Customer resource sponsors with and without a BPA acquisition contract. The financing analysis was prepared under contract by Public Financial Management (PFM), BPA's current financial advisor, and is included in the Study, WP-07-E-BPA-50, Appendix A.

Q. *Please describe the primary conclusion that can be drawn from the financing analysis.*

A. The primary conclusion that can be drawn from the financing analysis is that for most types of financing there is a positive benefit from BPA providing financial backing to the resources financed in the Program Case when compared to the financing costs projected in the 7(b)(2) Case, where resource financings do not receive the benefit of BPA financial backing.

Q. *Please summarize the financing analysis' specific conclusions regarding the financing of specific resource types using different debt maturities.*

A. For generation or conservation resources financed with 25-year public Joint Operating Agency (JOA) revenue bonds, the financing analysis (*see* Study, WP-07-E-BPA-50, Appendix A, Section 3, Table A) provides that resources financed with BPA backing in the Program Case would have received financing at a rate of 4.98 percent, compared to a higher rate of 5.17 percent for the 7(b)(2) Case without BPA financial backing. Thus, long-term resource investments financed over 25 years would receive an 19 basis point advantage in the Program Case over the 7(b)(2) Case. If generation or conservation resources were financed with 20-year public JOA revenue bonds backed by BPA in the Program Case, they would have received a more favorable financing rate of 4.91 percent compared to a higher rate of 5.09 percent for the 7(b)(2) Case without BPA financial backing. If generation or conservation resources were financed with 15-year public JOA revenue bonds backed by BPA in the Program Case, they would have received a more favorable financing rate of 4.68 percent compared to a higher rate of 4.85 percent for the 7(b)(2) Case without BPA financial backing. The resulting financial benefit from BPA's financial backing in the Program Case for 20- and 15-year financings would be 18 and 17 basis points, respectively. The financial analysis also provides estimates of interest rate differentials with and without a BPA acquisition contract for named resources, such as Cowlitz Falls. These conclusions are found in the Study, WP-07-E-BPA-50, Appendix A, Section 3, Table A.

Q. Was the financing analysis conducted using the same methodology that was used in the WP-07 Final Proposal?

A. Yes, in large part. In performing the financing analysis, PFM generally used the same methodology that was used in the WP-07 Final Proposal. As in past financing analyses, the projected interest rates for debt with BPA backing and JOA-issued debt without BPA backing are based on historical borrowing costs for different rating categories of bonds previously issued. However, the types of debt and the time periods examined are different. Past financing analyses relied primarily on the Bond Buyer 25-Bond Revenue Bond Index, which was not specific to electric power related financings. Past financing analyses also used a historical range of years dating from 1982 to 2004. *See* Study, WP-07-E-BPA-50, Appendix A, Table B. The current financing analysis relies primarily on historical rate differentials for A and AA rated revenue bonds that are specific to the electric utility industry and based on years dating from 1998 to 2007. *See* Study, WP-07-E-BPA-50, Appendix A, Table C. The financial data in the current study was obtained from the Bloomberg Capital Market yield curve indices. PFM has broad professional experience in matters concerning credit markets, the activities of BPA and other public and private utilities in the Pacific Northwest, and other utilities located throughout the country. PFM used its professional judgment in revising and developing assumptions surrounding the projection of interest rates for the different types of resources using the different debt maturities that were present in the resource stack.

Q. How were the results of the financing analysis applied in the 7(b)(2) rate test?

A. When additional resources are needed to meet 7(b)(2) Customers' loads in the 7(b)(2) Case that are in excess of the capability of FBS resources, section 7(b)(2)(D) provides that three types of resources are used in the 7(b)(2) Case resource stack to meet these loads. They are: Type 1, actual and planned resource acquisitions by BPA from 7(b)(2) Customers consistent with the Program Case; Type 2, existing 7(b)(2) Customer resources not currently dedicated to regional loads; and Type 3, additional resources at the average cost of actual and planned resource acquisitions by BPA from non-7(b)(2) Customers consistent with the Program Case.

Type 1 resources within the resource stack are: Cowlitz Falls Hydro Project, Idaho Falls Hydro Project, Georgia Pacific Wauna, billing credit resources, and conservation resources. The interest rate differential of an additional 5 basis points identified in the financial analysis for the Cowlitz Falls Hydro resource is reflected in the debt service costs for this resource within the resource stack. The additional 19 basis points in financing costs for billing credit resources in the 7(b)(2) Case identified in the financing analysis were factored into the costs contained in the resource stack for those resources. The financing analysis' projection for financing conservation resources for terms of 15- and 20-years using interest rates of 4.85 percent and 5.09 percent for the 7(b)(2) Case were factored into the resource costs for conservation resources within the resource stack.

Type 2 resources contained in the resource stack that were used to meet the loads in the 7(b)(2) Case are The Dalles Fishway, Pacific Northwest Generating Cooperative's (PNGC) share of Boardman, and Nine Canyon Wind, which were not dedicated to be serving preference customer loads during the 7 (b)(2) Case rate test period. Type 2 resources do not require a financial analysis because they are already financed and constructed without a BPA acquisition contract. *See* Section 7(b)(2) Implementation Methodology ROD, b-2-84-F-02, Section III, page 12, footnote 8.

Section 6: Resource Acquisitions

Q. Were 7(b)(2) Customer loads the same in the Program and 7(b)(2) Cases?

A. No. As provided in the *Proposed Methodology* (*see* Study, WP-07-E-BPA-50, Attachment B), 7(b)(2) Case customer loads were increased by the amount of actual or planned conservation included in developing the Program Case loads.

Q. Were resources needed in addition to FBS resources to serve the 7(b)(2) Customers' loads in the 7(b)(2) Case?

A. Yes. Additional resources were needed to serve the 7(b)(2) Customer loads from the start of the test period.

Q. How was the amount of additional resources needed to serve the 7(b)(2) Customers' loads in the 7(b)(2) Case calculated?

A. The RAM2007 model conducts a load/resource balance calculation in the 7(b)(2) Case for each year of the test period.

Q. How was the 7(b)(2) Case PF load forecast determined?

A. The 7(b)(2) Customer load forecast for the 7(b)(2) Case begins with the PF Preference loads from the Program Case and adds load associated with conservation resource acquisitions. Over the test period, the increase in 7(b)(2) Customer load over and above the Program Case PF Preference load due to foregone conservation is approximately 703 aMW. No direct sales to direct service industrial (DSI) customers are forecast for the rate period; therefore, no additional 7(b)(2) Customer load was assumed for within or adjacent DSIs in the 7(b)(2) Case.

Q. How were resources added to serve the 7(b)(2) Case load?

A. As established in the *Proposed Methodology* and as described above, three types of additional resources may be added to serve 7(b)(2) Customer loads. They are: Type 1, actual and planned resource acquisitions by BPA from 7(b)(2) Customers consistent with the Program Case; Type 2, existing 7(b)(2) Customer resources not currently dedicated to regional loads; and Type 3, additional needed resources at the average cost of actual and planned resource acquisitions by BPA from non-7(b)(2) Customers consistent with the Program Case.

A cost was calculated for each of the first two types of resources. Type 1 and Type 2 resources were stacked together in least-cost-first order in discrete increments reflecting the actual size of the resource or the increment actually acquired by BPA. These resources were assumed to come on-line in the order in which they were stacked to meet the 7(b)(2) Customer loads after FBS resources are exhausted. Whenever conservation or a billing credit resource was the least-cost resource selected, the amount (megawatts) of conservation or billing credit was treated as a reduction to the 7(b)(2) Customer loads consistent with its treatment in the Program Case.

Q. *Were any Type 3 resources required to meet 7(b)(2) Case loads in performing the rate test?*

A. No.

Section 7: Non-Dedicated Resources

Q. *Has BPA identified any Type 2 resources (existing 7(b)(2) Customer resources not dedicated to regional loads under section 5(b) of the Northwest Power Act)?*

A. Yes. Section 7(b)(2)(D)(ii) of the Northwest Power Act provides that, in addition to FBS resources, 7(b)(2) Customers' loads in the 7(b)(2) Case are met with "resources not committed to load pursuant to section 5(b)." BPA's *Proposed Interpretation* also refers to "resources owned or purchased by the 7(b)(2) Customers, and not dedicated to load by public agencies and investor-owned utilities pursuant to section 5(b)." BPA has identified a limited number of resources satisfying these requirements. The Dalles Fishway, PNGC's share of Boardman, and Nine Canyon Wind are currently not dedicated to load. These resources total about 62 aMW.

Q. *Why are the Mid-Columbia resources identified in the WP-07 Final Proposal excluded from the resource stack?*

A. In reviewing these resources for BPA's 1996 rate case, BPA identified resource capability associated with the Mid-Columbia dams (Wells, Rocky Reach, Rock Island, Wanapam, and Priest Rapids) owned by 7(b)(2) Customers (Douglas PUD, Chelan PUD, and Grant PUD) that were not used to meet regional preference customer loads.

The WP-07 Final Proposal included these resources because the 1984 *Legal Interpretation* and 1984 *Implementation Methodology* directed that resources not dedicated to "their own load" were to be included in the resource stack. The *Proposed Interpretation* has revised this instruction to include resources "not dedicated to load by public agencies or investor-owned utilities pursuant to section 5(b)." Because the Mid-Columbia resources are dedicated to IOU load, they are not included in the resource stack. (*See* Doubleday, *et al.*, WP-07-E-BPA-60, Section 8, for a discussion on the treatment of this issue in the Lookback analysis.)

Q. *All else being equal, what is the effect of removing the Mid-Columbia resources from the 7(b)(2) Case resource stack?*

A. The Mid-Columbia resources are low-cost resources and when they were needed to serve 7(b)(2) Customer load in the 7(b)(2) Case, they had the effect of lowering the 7(b)(2) Case rates, increasing the rate test trigger, and lowering the net REP benefits. Now that the Mid-Columbia resources are removed from the stack, smaller and higher cost resources must be used to serve load not served by the FBS resources in the 7(b)(2) Case. All else being equal, this will cause the 7(b)(2) Case rates to be higher, decreasing the rate test trigger, and increasing the net REP benefits.

Section 8: Conservation

Q. Please describe how conservation savings and related costs were formulated in conducting the 7(b)(2) rate test in the initial WP-07 rate proceeding.

A. A description of how conservation savings and related costs were formulated in conducting the 7(b)(2) rate test for the WP-07 Initial Proposal is contained in Keep, *et al.*, WP-07-E-BPA-27.

Q. Does BPA propose any changes to its formulation of conservation savings and costs as reflected in the WP-07 Final Proposal?

A. No.

Q. What assumptions were used regarding the capitalization and financing of conservation in the Program Case, and how are those assumptions different than those used in the 7(b)(2)Case?

A. The Program Case reflects BPA's actual accounting and financing policies. These policies have to support debt management considerations (debt optimization with Energy Northwest (ENW)), capital investment priorities, and other dynamic business management issues that BPA faces in operating and maintaining the FCRPS for the region. In the spring of 2005, BPA adopted a conservation policy of capitalizing and amortizing conservation investments over a period of five-years. During FY 1995-2005, BPA issued $452 million in conservation bonds with varying terms, ranging from 3 to 20 years with a weighted average interest rate of 5.89 percent. In the 2007 Program Case, BPA is projecting that it will issue $257 million for conservation investments using five-year bonds over the years 2007-2013 with a weighted average interest rate of 6.18 percent.

In the 7(b)(2) Case, conservation financing is based on the assumption that BPA would acquire conservation savings from a JOA (*see* Study, WP-07-E-BPA-50, Appendix A) that is formed by consumer-owned utilities (COUs). It is assumed that the

JOA would have adopted a conservation capitalization/amortization policy that was based on the useful life of conservation investments based on the Northwest Power and Conservation Council (NPCC) estimates. The NPCC's estimates for the average useful life of conservation measures was 20 years for investments that occurred during 1982-2001 and 15 years for investments made after 2001. PFM's financing analysis projected that the JOA would have obtained financing at a cost of 5.09 percent and 4.85 percent for 20- and 15-year maturities as outlined in Section 5 above. The 7(b)(2) Case uses the financing analysis interest rates in calculating the debt service expense to be included in the revenue requirements for conservation investments selected from the resource stack. The interest rate differential between the Program Case and the 7(b)(2) Case reflects the difference in capitalization policies and financing assumptions used in the two cases.

Q. Do you propose any change to the assumptions used regarding the capitalization and financing of conservation in the Program Case?

A. No. We do not propose any changes to the historical capitalization and financing of conservation in the 7(b)(2) Case resource stack. However, we recognize that whereas annual programmatic conservation comes on one annual program at a time each year in the Program Case, in the 7(b)(2) Case several of these same annual programmatic conservation resources can be brought on in a single year. As a consequence of BPA's annual programmatic conservation being in the 7(b)(2) Case resource stack, some financing assumption other than the actual historical practice may be reasonable in the 7(b)(2) Case.

Q. Are you proposing a different financing assumption at this time?

A. No.

Q. In the WP-07 Final Proposal, did you remove conservation from the resource stack based on whether the conservation measures were obsolete?

A. No.

Q. Do you propose to continue this approach in the Supplemental Proposal?

A. No. In this Supplemental Proposal, a programmatic conservation resource was assumed to be obsolete if its year of origin plus its expected life totaled more than the last year of the rate test period in question, 2013. The expected life of a programmatic conservation resource in the 7(b)(2)(D) resource stack is assumed to be equal to the time period over which the resource is amortized. After this period has expired, it is assumed that the conservation resource produces no measurable savings. For purposes of setting FY 2009 rates, the time period over which conservation resources are amortized is 20 years. Therefore, programmatic conservation resources from 1982 to 1993 have been determined to be obsolete and have been removed from consideration for the calculation of base rates for the FY 2009-2013 rate test period.

Q. All else being equal, what is the effect of removing obsolete annual programmatic conservation resources?

A. Removing obsolete programmatic conservation from the 7(b)(2) Case resource stack has the effect of lowering the load forecast, because the savings from the obsolete conservation programs are not added as extra load in the 7(b)(2) Case. Given that the Mid-Columbia resources are excluded from the stack, the remaining resources taken from the stack are likely to be more expensive than the FBS. Therefore, all else being equal, with a lower load forecast and the concomitant fewer resources taken from the stack to serve load, 7(b)(2) Case rates will be lower, increasing the rate test trigger, and lowering net REP benefits.

Section 9: Reserve Benefits

Q. Please describe the reserve benefits used in the 7(b)(2) rate test.

A. For the Supplemental Proposal, no BPA sales to the DSIs are forecast in the Program Case, and thus no DSI loads are present in the 7(b)(2) Case. *See* Gustafson, *et al.*, WP-07-E-BPA-18. Because no BPA sales to the DSIs are forecast, the reserve benefits provided under the Northwest Power Act from DSIs are also forecast to be zero. No other reserve benefits are forecast to be acquired under provisions of the Northwest Power Act.

Section 10: Changes in the Rate Analysis Model

Section 10.1: RAM2007 Models

Q. What type of computer model is required to conduct the 7(b)(2) rate test?

A. In order to calculate the annual PF rates for the Program and 7(b)(2) Cases, a model that simulates BPA's ratemaking processes should be used. The Program Case modeling produces a forecast projection of annual rates that reflect BPA's actual forecast data and policies for the rate period, extended to the four subsequent years, while the 7(b)(2) Case modeling allows the incorporation of the 7(b)(2) assumptions.

Q. What computer models has BPA previously used to conduct the 7(b)(2) rate test?

A. In BPA's WP-85 rate case, when BPA first conducted the 7(b)(2) rate test, BPA used the FORTRAN-based SPM. BPA also used the SPM in subsequent wholesale power rate cases through the WP-96 rate case. In BPA's WP-02 rate case, BPA used the 2002 Rate Analysis Model (RAM2002), which consists of five large Excel spreadsheets that work together by the use of Visual Basic macros. BPA now uses the 2007 Rate Analysis Model (RAM2007), a single automated Excel spreadsheet, to conduct the test.

Q. Why did you develop RAM2007 to conduct the 7(b)(2) rate test and to prepare rates for the WP-07 rate period?

A. The need for greater efficiency and flexibility in rate analysis prompted us to develop RAM2007. Although RAM2002 was developed specifically for the five-year WP-02 rate period and the associated nine-year 7(b)(2) test period, RAM2007 was developed to provide the capability to forecast rates over a ten-year period. In addition, whereas

RAM2002 was designed to accurately model the WP-02 rate case assumptions, RAM2007 accommodates different scenarios and forecasts 7(b)(2) rate test triggers and rates for the 2007-2009, 2009, 2010-2011, and 2012-2013 rate periods (assuming BPA moves to two-year power rate periods in the future).

Q. Please briefly describe RAM2007.

A. RAM2007 is a large Excel spreadsheet model that is automated with Visual Basic macros. RAM2007 is intended to be more user-friendly than RAM2002.

Q. Please describe how RAM2007 is more user-friendly.

A. RAM2007 is operated from a pull-down menu and explicitly shows the rate results after each ratemaking step. RAM2007 automatically determines which of the potential exchanging utilities will be exchanging as the unbifurcated PF and PF Exchange rates are developed. RAM2002 relied on inspection by the user to determine the number of utilities participating in the REP. RAM2007 calculates the PF Slice product cost for each year and incorporates those data in the calculation of the PF Preference rate. Because Slice contracts had not yet been signed at the time of the WP-02 rate case, RAM2002 did not use Slice product cost data in the calculation of rates.

Q. Is the RAM2007 model you used to conduct the Supplemental Proposal 7(b)(2) rate test also used to develop the Supplemental Proposal power rates?

A. Yes. The forecasts and policy assumptions used in the Program Case of the 7(b)(2) rate test are also used in the calculation of posted rates for the Supplemental Proposal. RAM2007 conducts the 7(b)(2) rate test as just one of several ratemaking steps to produce annual rates. Although RAM2007 grouped three years (36 months) of costs, credits, and sales together to calculate average rates for the original three-year rate period for the WP-07 Final Proposal rate test, it now uses a one-year rate period (FY 2009) for the Supplemental Proposal.

Q. *How does RAM2007 incorporate those portions of the* Proposed Methodology *that determine how the 7(b)(2) projections are made?*

A. The 7(b)(2) sections of RAM2007 differ from the Program Case sections of RAM2007 by the five section 7(b)(2) assumptions:

(1) *The within or adjacent DSI loads are added to the PF sales forecast, and no IP load or rate class is assumed.* For the rate period, no direct service to the DSIs has been forecast, therefore there is no addition to PF load due to DSI service in the RAM2007 7(b)(2) Case. Also, DSI financial benefits are excluded from the 7(b)(2) Case because BPA does not have DSI contracts in the 7(b)(2) Case.

(2) *7(b)(2) Customers are served with FBS resources not obligated to other non-preference loads under contracts existing as of the effective date of the Northwest Power Act.* For the rate period, the FBS available to serve PF load is modeled in such a way that it is slightly larger in the 7(b)(2) Case than in the Program Case due to this provision. However, this is an artifact of the modeling; the size of the FBS actually is the same in both Cases.

(3) *No section 5(c) REP takes place, and no PF Exchange load or rate class is assumed.* For the rate period, REP costs and loads are not included in the 7(b)(2) Case.

(4) *A section 7(b)(2)(D) resource stack with resources sorted from least to most costly has been constructed to serve 7(b)(2) Customers after the FBS is exhausted. In addition, PF sales forecasts are increased by forecasts of annual conservation resources that are included in the 7(b)(2)(D) resource stack.* For the rate period, 7(b)(2) Customer load in the 7(b)(2) Case has been increased by conservation resources and the model goes to the 7(b)(2)(D) resource stack to serve 7(b)(2) Customer load in the rate test period. The amount of conservation has been limited to a level that BPA is assumed to be acquiring.

5. *<u>Reserves are included as an increased cost to the 7(b)(2) Customers. The cost of 7(b)(2) Customer resources reflects that financing benefits under provisions of the Northwest Power Act are not available in the 7(b)(2) Case.</u>* For the rate period, no reserves are forecast to be acquired by BPA and increased resource costs due to the removal of financing benefits are incorporated in the 7(b)(2)(D) resource stack.

Q. How is RAM2007 organized?

A. RAM2007 now has two main steps: a Rate Design Step and a Slice Separation Step.

Q. Please provide a brief description of how the RAM2007 Rate Design Step works.

A. The RAM2007 Rate Design Step follows BPA's rate directives by determining the costs associated with the three resource pools (FBS resources, Exchange resources, and new resources) used to serve loads and then allocating the resource costs to the rate pools (7(b) (PF loads), 7(c) (IP loads), and 7(f) (NR loads). After the initial allocation of costs, the Northwest Power Act requires that some rate adjustments be made, such as those described in sections 7(b) and section 7(c) of the Act. RAM2007 performs these rate adjustments, including the 7(b)(2) rate test, in its Rate Design Step. The Rate Design Step of RAM2007 concludes with the calculation of the Rate Design Step rates. *See* Brodie, *et al.*, WP-07-E-BPA-70, Section 4, for a fuller discussion of RAM2007.

Q. Please provide a brief description of the Slice Separation Step.

A. In the Rate Design Step, costs were allocated to the various rate pools, including the PF Preference rate pool that contained all firm PF Preference load. The Slice Separation Step separates out the PF Slice product revenues, revenue credits, and firm loads from the overall PF Preference rate pool, leaving the costs that must be covered by the remaining non-Slice product PF Preference load through posted PF Preference energy, demand, and load variance charges.

Section 10.2: Principal Modeling Changes

Q. Have you made any changes to its rate development modeling for the Supplemental Proposal?

A. Yes. There are four principal changes to the RAM2007 models:

(1) Although the RAM2007 model used in the WP-07 Final Proposal had a Subscription Step to allocate REP Settlement Agreement costs, the RAM2007 model used in the Supplemental Proposal does not use the Subscription Step. In the Supplemental Proposal, rates are set to collect the cost of a traditional REP in the Rate Design Step.

(2) The composition of the 7(b)(2)(D) resource stack was changed: annual programmatic conservation resources that had become obsolete were removed and the Mid-Columbia resources were excluded as described below. The net impact of these changes to the resource stack was to make the cost of acquiring resources in the 7(b)(2) Case more expensive.

(3) BPA changed the way it models the section 7(b)(3) reallocation of the 7(b)(2) PF Preference rate protection amount. This is explained in greater detail below.

(4) The amount of the secondary revenue credit applied to rates in the Rate Design Step has been increased. This is explained in greater detail below.

Section 10.3.1: Elimination of Subscription Step

Q. Is the stepped ratemaking (Rate Design Step and Slice Separation Step) similar to that used in RAM2007 for the WP-07 Final Proposal?

A. Yes, except that RAM2007 for the WP-07 Final Proposal developed rates in a three-step process and now one of those steps, the Subscription Step, has been removed. In the WP-07 Final Proposal, the Program Case rates for the 7(b)(2) rate test were calculated in the Rate Design Step using all costs, including a forecast of gross exchange costs for the

IOUs. BPA then conducted a Subscription Step to reallocate costs arising from the REP Settlement Agreements. Then the Slice Separation Step was applied.

Q. *Why was the Subscription Step removed?*

A. The Subscription Step reallocated costs arising from the REP settlements. On May 3, 2007, the United States Court of Appeals for the Ninth Circuit held that BPA improperly allocated REP Settlement Agreement costs to preference customer rates in BPA's WP-02 rate proceeding. *See* Bliven, *et al.*, WP-07-E-BPA-52. Therefore, the Subscription Step has been removed from RAM2007.

Section 10.3.2: 7(b)(2) Case Resource Stack Modeling Changes

Section 10.3.2.1: Programmatic Conservation Resource Modeling Changes

Q. *Do you propose any changes to the WP-07 Final Proposal treatment of conservation to address the obsolescence of conservation measures?*

A. Yes. For purposes of ratemaking, a programmatic conservation resource was assumed to be obsolete if its year of origin plus its expected life totaled more than the last year of the rate test period in question, FY 2013. The expected life of a programmatic conservation resource in the 7(b)(2) Case resource stack is assumed to be equal to the time period over which the resource is amortized. After this period has passed, it is assumed that the conservation program produces no more measurable savings and that it no longer being acquired by BPA. For FY 2007-2013, that time period is 20 years. Therefore, programmatic conservation resources from FY 1982 to FY 1993 have been determined to be obsolete and have been removed from consideration for the calculation of base rates for the FY 2007-2013 rate test period.

Q. *All else being equal, what is the effect of removing obsolete annual programmatic conservation resources?*

A: Removing obsolete programmatic conservation from the 7(b)(2) Case resource stack has the effect of lowering the load forecast, because the savings from the obsolete conservation programs are not added as extra load in the 7(b)(2) Case. Given that the Mid-Columbia resources are removed from the stack, the remaining resources taken from the stack are likely to be more expensive than the FBS. Therefore, all else being equal, with a lower load forecast and the concomitant fewer resources taken from the stack to serve load, 7(b)(2) Case rates will be lower, increasing the rate test trigger, and lowering net REP benefits.

Q. *Do you propose any changes to the capitalization and financing of programmatic conservation resources in the 7(b)(2) Case?*

A. No. We do not propose any changes to the historical capitalization and financing of conservation in the 7(b)(2) Case resource stack. However, we recognize that whereas annual programmatic conservation comes on one annual program at a time each year in the Program Case, in the 7(b)(2) Case several of these same annual programmatic conservation resources can be brought on in a single year. As a consequence of BPA's annual programmatic conservation being in the 7(b)(2) resource stack, some financing method other than the actual historical practice may be reasonable in the 7(b)(2) Case.

Section 10.3.2.2: Mid-Columbia Resources Modeling Changes

Q. *For this WP-07 Supplemental proposal, do you propose a change in the model treatment of the Mid-Columbia resources from the WP-07 Final Proposal treatment of those resources?*

A. Yes. The Mid-Columbia resources have been taken out of the 7(b)(2) Case resource stack. For purposes of this Supplemental Proposal, this change is assumed to have been made in the recalculation of WP-02 base rates, as discussed below.

Q. *In developing the WP-02 Final Proposal base rates, did BPA identify any Type 2 resources (existing 7(b)(2) Customer resources not currently dedicated to regional loads)?*

A. Yes. Section 7(b)(2)(D)(ii) of the Northwest Power Act provides that, in addition to FBS resources, 7(b)(2) Customers' loads in the 7(b)(2) Case are met with "resources not committed to load pursuant to section 5(b)." In developing the WP-02 Final Proposal base rates, BPA assumed the portion of the Mid-Columbia hydro resources owned by 7(b)(2) Customers but whose power was contracted for by regional IOUs was a Type 2 resource. *See* 7(b)(2) Rate Test Study Documentation, WP-02-FS-BPA-06A, page 47, Table 7b2 Resource_02.

Q. *Please describe the treatment of Type 2 resources in the WP-02 rate case.*

A. In the WP-02 Initial Proposal, BPA forecast that FBS resources would be insufficient to meet 7(b)(2) Customers' loads in the 7(b)(2) Case. BPA concluded that it would therefore have to use resources from the 7(b)(2)(D) resource stack in order to serve such loads. One issue that arose in the WP-02 rate case was whether power from the Mid-Columbia dams owned by preference customers but sold to IOUs constituted a Type 2 resource that should be included in the resource stack. This issue had previously arisen in BPA's WP-96 rate case. Although BPA discussed this issue in the WP-96

ROD, BPA did not have to decide the issue because the FBS turned out to be sufficient to meet the 7(b)(2) Customers' loads and the issue was moot.

As noted above, the Mid-Columbia issue arose again in the WP-02 rate case. However, the Mid-Columbia resources owned by 7(b)(2) Customers but sold to IOUs were not used in the WP-02 Final Proposal because the augmented FBS resource pool was large enough to serve the 7(b)(2) Case loads without need for resources from the stack. The increased size of the FBS was due to increased system augmentation in the Program Case that was necessary to serve the total PF, IP, RL, and FPS loads. Despite the fact that the issue was moot, BPA's DSI customers raised arguments that had not been raised in the WP-96 rate case that supported excluding the Mid-Columbia resources from the resource stack. In the WP-02 Record of Decision (ROD), BPA acknowledged that the Mid-Columbia issue was moot because it had no bearing on the rate calculation and that a different treatment (excluding the Mid-Columbia resources from the resource stack) was possible if the issue became ripe in subsequent rate cases.

Q. Did the Mid-Columbia issue become ripe in the Lookback calculations?

A. Yes. The FY 2002-06 Lookback analysis used a load/resource balance as of June 2001, now assuming no REP settlements, is significantly different than the WP-02 Final Proposal load/resource balance. This difference is due to removing RL sales and using what was assumed FPS sales to serve increasing PF Preference loads. As a result of this changed load/resource balance, resources from the 7(b)(2) resource stack are required during some of the test period years. Thus the Mid-Columbia issue is ripe for the Lookback calculations.

Q. Please describe BPA's proposed treatment of the Mid-Columbia resources for the WP-02 Lookback 7(b)(2) rate test.

A. Although BPA previously considered including the Mid-Columbia resources in the resource stack in its WP-96 and WP-02 rate cases, BPA never had to formally decide the issue because FBS resources were sufficient to serve 7(b)(2) Customer loads in the WP-96 and WP-02 cases. Similarly, due to the Partial Resolution of Issues in BPA's WP-07 Final Proposal, BPA did not have to address the issue at that time. After reviewing the issue more thoroughly, BPA has proposed a revised *Legal Interpretation* and a revised *Implementation Methodology*. *See* Study, WP-07-E-BPA-50, Attachments A and B. If BPA had been required to decide the Mid-Columbia issue in BPA's WP-02 Final Proposal, BPA assumes it would have come to the same conclusions reached in the *Proposed Interpretation* and *Proposed Methodology*. BPA proposes that the Mid-Columbia resources should not be included in the resource stack for the section 7(b)(2) rate test in the WP-02 and WP-07 Lookback calculations, nor for the Supplemental Proposal calculation of FY 2009 rates, that is the subject of this testimony.

Q. All else being equal, what is the effect of excluding the Mid-Columbia resources from the 7(b)(2) resource stack?

A. The Mid-Columbia resources are low-cost resources. If they had been included in the resource stack and resources in addition to the FBS were required in the 7(b)(2) Case, they would have lowered the 7(b)(2) Case rates, thereby increasing the rate test trigger and lowering net REP benefits. When the Mid-Columbia resources are excluded from the stack, smaller and higher cost resources must be used to serve load not served by the FBS resources in the 7(b)(2) Case. All else being equal, this causes the 7(b)(2) Case rates to be higher, thereby decreasing the rate test trigger and increasing net REP benefits.

Section 10.3.3: 7(b)(3) Reallocation Modeling Changes

Q. Have you changed the way you model the 7(b)(3) reallocation of the 7(b)(2) PF Preference rate protection amount and if so, will that change to the 7(b)(3) reallocation method actually affect the outcome of the 7(b)(2) Rate Test?

A. Yes. We do have a different 7(b)(3) reallocation method and the methodological change does have the potential to change the outcome of the 7(b)(2) Rate test.

Q. Please describe the new 7(b)(3) reallocation of the 7(b)(2) PF Preference rate protection amount.

A. The new 7(b)(3) reallocation method begins by calculating "Preliminary REP Benefits" by multiplying the difference between the exchanging utility's ASC and the base PF Exchange rate. The base PF Exchange rate is the unbifurcated PF rate plus a transmission and ancillary services adder. After the 7(b)(2) rate test has been conducted and the 7(b)(3) rate protection amount determined, that amount is allocated to the individual exchanging utilities according to their *pro rata* share of the "Preliminary REP Benefits." A Supplemental 7(b)(3) charge is determined for each individual exchanging utility and an annual average PF Exchange rate is calculated for each individual exchanging utility by adding the Supplemental 7(b)(3) charge to the base PF Exchange rate.

The result of this new 7(b)(3) reallocation methodology is that utilities with ASCs above the base PF Exchange rate will continue receive REP benefits compared with the former methodology. However, it is possible, depending on the results of the rate test that no utilities would get benefits despite this reallocation methodology. Utilities with relatively low ASCs will get lower PF Exchange rates and utilities with relatively higher ASCs will get higher PF Exchange rates.

Q. *How does this new 7(b)(3) reallocation methodology affect the outcome of the 7(b)(2) rate test?*

A. Because the unbifurcated PF rate before the 7(b)(2) rate test is conducted, is lower than the average PF Exchange rate, assuming a non-zero 7(b)(2) trigger, and because all utilities with ASCs above that lower unbifurcated PF rate will participate in the REP, more utilities will participate under the new methodology. With more utilities participating in the REP, the gross costs of the REP in the Program Case will be greater and, therefore, the 7(b)(2) rate test trigger will be higher.

Q. *Does the proposed 7(b)(3) reallocation methodology change the PF Preference rate?*

A. No. The is unaffected by the 7(b)(3) reallocation methodology. The increase in gross costs of the REP is offset by the increased trigger. In theory, the PF Preference rate should be the same under the former reallocation methodology and the proposed reallocation methodology. In practice, very small differences in the PF Preference rate may occur due to the rounding of the rate test trigger.

Section 10.3.4: Secondary Revenue Credit Modeling Changes

Q. *Have you changed the way it models the secondary energy revenue credit for this Supplemental Proposal?*

A. Yes. In the WP-07 Final Proposal, BPA used only the non-Slice portion (77.37 percent) of the secondary energy produced by the Federal Columbia River Power System (FCRPS) in the calculation of rates. The non-Slice portion is the amount of revenue that BPA forecasts it will earn from the sale of 77.37 percent of the FCRPS secondary energy in the West Coast electric markets. In addition to these sales, the other 22.63 percent of the secondary produced by the FCRPS is sold as a part of the Slice product at the PF Slice rate. BPA now proposes using revenues as if all secondary energy was sold in the electric markets in the calculation of rates in the Rate Design Step ratemaking.

Q. Why do you now use the total market value of secondary energy as a revenue credit in the Rate Design Step?

A. In the Rate Design Step, the PF rate pool includes the firm portion of the Slice product sales. Therefore, it is more proper from a general ratemaking prospective to include the a secondary revenue credit produced by the FCRPS in the rate pool that is paying the costs of the FCRPS at this point in the ratemaking process, the total PF rate pool. After the Rate Design Step, in the Slice Separation Step, the Slice product, costs, loads, and secondary revenue credit are removed from the PF Preference load pool.

Q. What is the secondary revenue credit forecast for FY 2009?

A. BPA expects the total secondary energy would produce about $743.9 million in revenues in FY 2009 if sold into the electric markets. Of the total revenue forecast of $743.9 million, 22.63 percent or about $168.3 million will instead be sold to BPA's Slice product customers at the PF Slice rate producing no incremental revenue. The remaining $575.6 million is forecast to be marketed by BPA and is a revenue credit to non-Slice rates. *See* WPRDS Documentation, WP-07-E-BPA-49A, Table 2.5.3, (RDS 11).

Section 10.3: Additional Modeling Changes

Q. Have other changes been made to the RAM2007 used in this Supplemental Proposal?

A. Yes. Some modeling changes have been made to the most current version of RAM2007. These changes were made to either correct errors in the calculations, make the calculations more transparent, to advance BPA policy goals more effectively, or to ensure that aspects of the *Proposed Methodology* are reflected in the rate modeling.

Q. Please describe the modeling change made concerning how resources taken from the 7(b)(2) Case resource stack are priced in the year they are brought on and beyond.

A. In the RAM2007 used in the WP-07 Final Proposal, the capital costs, operations and maintenance costs, and fuel costs for each resource included in the 7(b)(2)(D) resource stack in were expressed in 1980 dollars. The annual cumulative total cost of the needed resources was determined as the resources were brought on-line for each year of the rate test period. The annual cumulative total in 1980 dollars was then escalated to the current year's dollars for each year of the test period. These calculations were accomplished using a macro and, therefore, the user was unable to easily follow the steps.

In the WP-07 Supplemental RAM2007, rather than have a macro select resources and keep track of the annual total costs, a table using lookup functions shows when a resource is selected from the stack and shows the annual costs for each individual resource brought on. The user is able to see each resource's cost contribution in each year it is operating and serving load, making the process more transparent.

Q. Are there any additional improvements in the model's pricing of additional resources taken from the 7(b)(2) Case resource stack?

A. Yes. Although the older version of RAM2007 added the capital costs, operations and maintenance costs, and fuel costs for each resource in 1980 dollars and then brought the total to current year dollars, the current version keeps the capitalized mortgage-type payment in the nominal dollars of the year in which the resource came on-line and escalates only the fuel and O&M costs each subsequent year. This modification recognizes that the annual payment associated with the capitalized portion of the resource's cost would not escalate over time. This is particularly relevant for BPA's programmatic conservation resources in the stack.

Q. Are you proposing a change to how resources are added, if needed to serve 7(b)(2) Customer load?

A. Yes. In the past, resources selected from the 7(b(2) Case resource stack were added in the full amount that was listed in the "Output" column in the stack; that is, the total resource was added even if only a fraction of its output was needed. Now, the *Proposed Methodology* instructs us that resources will be brought on-line in the exact amount required to meet the 7(b)(2) Customers' remaining general requirements. *See* Study, WP-07-E-BPA-50, Attachment B.

Q. Please describe the modeling changes made to accommodate add only the power needed in each year rather than the entire last resource.

A. The provision in the *Proposed Methodology* has not been fully implemented in RAM2007 for the Supplemental Proposal. As a modeling shortcut, we chose to sell the excess firm power caused by adding the entire resource at the levelized cost of that resource. In this way, the revenue from the sale of the unneeded portion of the marginal resource will offset the cost of the unneeded portion. In this way, the rates for any year will recover only the costs of the portion of the resource that was used to serve 7(b)(2) Customer loads.

Section 11: Summary of 7(b)(2) Rate Test

Q. What are the results of the Supplemental Proposal 7(b)(2) rate test?

A. The 7(b)(2) rate test triggers by 5.2 mills/kWh and 7(b)(2) Customers are eligible for rate protection of approximately $327 million in FY 2009.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY of

DANIEL H. FISHER, GERARD BOLDEN, BYRON G. KEEP,

GREG C. GUSTAFSON, and ALLAN E. INGRAM

Witnesses for Bonneville Power Administration

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TESTIMONY of

DANIEL H. FISHER, GERARD BOLDEN, BYRON G. KEEP,

GREG C. GUSTAFSON, and ALLAN E. INGRAM

Witnesses for Bonneville Power Administration

SUBJECT: SUPPLEMENTAL RATE DESIGN

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Daniel H. Fisher. My qualifications are contained in WP-07-Q-BPA-61.

A. My name is Gerard Bolden. My qualifications are contained in WP-07-Q-BPA-05.

A. My name is Byron G. Keep. My qualifications are contained in WP-07-Q-BPA-22.

A. My name is Greg C. Gustafson. My qualifications are contained in WP-07-Q-BPA-14.

A. My name is Allan E. Ingram. My qualifications are contained in WP-07-Q-BPA-18.

Q. Please describe the purpose of your testimony.

A. The purpose of our testimony is to sponsor the rate design portion of BPA's 2007 Supplemental Wholesale Power Rate Development Study (WPRDS), WP-07-E-BPA-49, Section 2, and the 2007 Supplemental Wholesale Power Rate Schedules (FY 2009) and 2007 General Rate Schedule Provisions (FY 2009), WP-07-E-BPA-51. The testimony describes changes to the PF-07 rates, now labeled PF-07R, for FY 2009.

Q. What is the general approach to rate design that is taken in this rate case?

A. The general approach BPA proposes for rate design is to continue to implement the Partial Resolution of Issues that was adopted in the WP-07 Final Proposal. *See* WPRDS, WP-07-E-BPA-49, Appendix 1.

Q. How is your testimony organized?

A. Section 1 is this introduction. Section 2 discusses the Demand, Energy, and Load Variance rates. Section 3 discusses the CRAC, the DDC, and the NFB Adjustment. Section 4 discusses changes proposed to the FPS rate schedule. Section 5 discusses changes to the PF Exchange rate. Section 6 discusses the Low Density Discount. Section 7 discusses the conservation and renewable program. Section 8 discusses the GTA Delivery Charge. We conclude with Section 9 on other changes to rate design.

Section 2: Demand, Energy, and Load Variance

Q. How will the Demand, Energy, and Load Variance Rates be calculated?

A. BPA proposes in this Supplemental Proposal to calculate rates for FY 2009 using the same method that was used in the WP-07 Final Proposal for rates in FY 2007-2008. An updated annual Revenue Requirement will be used to proportionately scale (*i.e.*, by an equal percentage applied to each rate) the WP-07 Final Proposal rate components downward. The relationship of the monthly Heavy Load Hour (HLH) and Light Load Hour (LLH) Energy rates, Demand rate, and Load Variance rate for the PF-07 rate schedules will be the template for the PF-07R rate schedules. *See* WP-07-E-BPA-49A, Table 2.7. The scaling of the rates will recover the revenue requirement in total when applied to the billing determinants in the revenue forecast and the revised revenue test. *See* Supplemental Revenue Requirement Study, WP-07-E-BPA-46.

Section 3: CRAC, DDC, and NFB Adjustments

Q. How would the proposed rates be adjusted for a CRAC, DDC, or an NFB Adjustment?

A. When necessary, the CRAC and DDC would be applied proportionally (*i.e.*, by an equal percentage change to each rate component to the HLH Energy, LLH Energy, and Load

Variance rates of the PF-07R, IP-07R, and NR-07R rate schedules. The increase in revenue recovered through the CRAC mechanism is limited to $36 million per year. *See* Supplemental Risk Analysis Study, WP-07-E-BPA-48, Section 3.3.3.

If a Trigger Event for the NFB Adjustment occurs, the $36 million cap on CRAC revenues can be exceeded up to the amount of the Financial Effects of the Trigger Event. *See* Supplemental Risk Analysis Study, WP-07-E-BPA-48, Section 3.4.1.1. Any amounts in excess of $36 million per year will be recovered through a proportional increase to the PF-07R, IP-07R and NR-07R Demand, Energy, and Load Variance rates.

Section 4: FPS Rate Changes

Q. What changes were made to the FPS rate schedule?

A. In Section II.A.1.1 the posted rates for Demand, HLH Energy, LLH Energy, and Capacity Without Energy were removed. A new Section II.E was added to define the pricing of reassignment or remarketing of surplus transmission.

Q. Why are you proposing to remove these posted rates?

A. All contracts referring to these rates have expired and they are no longer needed. New contracts will be based on negotiated prices.

Q. What rates will BPA use for surplus firm sales if there are no posted rates?

A. The FPS rate schedule provides for a flexible rate for new contracts for surplus energy and capacity.

Q. Why were the posted rates included in the FPS-07 rate schedule?

A. BPA had contracts that referred to these posted rates. These contracts have expired.

Q. Are there any other changes proposed for the FPS rate schedule?

A. Yes, BPA is proposing to add a section to the FPS rate schedule to allow Power Services to remarket its excess transmission capacity to other entities consistent with the terms of a transmission provider's Open Access Transmission Tariff. This provision was under the 2007 General Rate Schedule Provisions (GRSPs), Section I.E. It has been deleted from the GRSPs and moved into the FPS rate schedule. This is appropriate because the FPS rate schedule is the schedule under which BPA sells any surplus.

Q. Are there any revenues forecast to be collected under this rate schedule?

A. No.

Section 5: PF Exchange Rate

Q. What is the PF Exchange rate?

A. The PF Exchange rate applies to BPA's power sales to utilities participating in the Residential Exchange Program (REP). The difference between BPA's PF Exchange rate and the exchanging utility's average system cost of resources (ASC), multiplied by the utility's residential and small farm load, equals the monetary benefits provided to the utility under the REP. The PF Exchange rate also applies to actual power sales under in lieu transactions. In lieu where BPA acquires a less expensive resource rather than the utility's resource priced at their ASC, resulting in a power sale in the amount of the in lieu resource.

Q. How has BPA previously developed the PF Exchange rate?

A. The PF Exchange rate is equal to the PF Preference rate (if the section 7(b)(2) rate test does not trigger) plus a transmission rate. If the 7(b)(2) rate test triggers, the trigger amount (7(b)(3) rate protection amount) is removed from the PF Preference rate and allocated through supplemental rate charges to all other power sold by the Administrator to non-preference customers. In previous rate cases where the 7(b)(2) rate test triggered, the 7(b)(3) amount was allocated *pro rata* to non-preference power sales.

Q. *Is there any change in the design of the PF Exchange rate?*

A. Yes. In the past, the design of the PF Exchange rate was consistent, but not identical, to the design of the PF Preference rate. That is, the PF Exchange rate included monthly demand and energy components. We now propose to modify the design of the PF Exchange rate into a single annual energy rate applicable to all months of the year.

Q. *Why are you proposing this change?*

A. There is no particular need for the PF Exchange rate to be time differentiated as with the PF Preference rate. Time differentiation is incorporated into the PF Preference rate to inform customers which time periods are more costly to serve load. The price signals in the PF Preference rate allow a customer to save more by reducing their load on BPA in more costly time periods and to save less when they reduce their load on BPA in less costly time periods.

This is not the case with the PF Exchange rate. This rate is used solely to determine the monetary benefits of exchanging utilities. It is used in conjunction with the utilities' ASCs, which are not time differentiated. The comparison of one rate that is time differentiated with a rate that is not approaches a level of accuracy in ratesetting that is neither warranted nor necessary. Also, because of the procedures that are being proposed to apply Lookback Amounts to IOU REP benefits, the application of a time differentiated PF Exchange rate is further unnecessary. *See* Marks, *et al.*, WP-07-E-BPA-62.

Q. *How does the* pro rata *7(b)(3) allocation method affect the REP benefits provided to exchanging utilities?*

A. If the section 7(b)(2) rate test does not trigger, the 7(b) rate (the unbifurcated PF rate) is used for both the PF Preference rate and the PF Exchange rate. In this circumstance, utilities with ASCs greater than the PF Exchange rate receive positive REP benefits. (Exchanging utilities with ASCs less than the PF Exchange rate were able to deem their

ASC equal to the PF Exchange rate to avoid paying REP benefits to BPA.) If the 7(b)(2) rate test triggers and the 7(b)(3) rate protection amount is allocated, in part, to the PF Exchange rate, high-ASC utilities that would receive reduced benefits and utilities with lower ASCs may receive no REP benefits whatsoever. This has previously occurred in the development of BPA's rates and subsequent implementation of the REP. In summary, under the *pro rata* allocation, fewer residential and small farm consumers of regional utilities receive REP benefits. Because the REP was originally intended to provide utilities, particularly investor-owned utilities, a form of access to the benefits of the Federal Columbia River Power System (FCRPS), (which consumer-owned utilities (COUs) receive directly through requirements power purchases at the PF Preference rate), the *pro rata* allocation limits the intent of the REP. Thus, a *pro rata* allocation limits BPA's ability to spread the benefits of the FCRPS as broadly as possible.

Q. How do you propose to change the development of the PF Exchange rate?

A. We are proposing a two-step process to develop the PF Exchange rate. The first step, as in the past, is calculating a base PF Exchange rate assuming a zero 7(b)(2) rate trigger, then comparing the base PF Exchange rate to the ASC of each exchanging utility to see if the individual utilities would qualify for REP benefits (*i.e.*, ASC greater than the base PF Exchange rate).

In the second step, for each exchanging utility qualifying for REP benefits in the zero trigger case then, in the event the 7(b)(2) rate test triggers, a utility-specific Supplemental 7(b)(3) charge will be developed. Thus, the PF Exchange rates (*i.e.*, the base PF Exchange rate plus the utility-specific Supplemental 7(b)(3) charges) will maintain the proportionality of REP benefits among exchanging utilities that was established in the first (zero trigger) step.

Q. *What is the import of your proposed 7(b)(3) allocation?*

A. Our proposed allocation allows a greater number of residential and small farm consumers of regional utilities to receive a form of benefit from the FCRPS. The total amount of REP benefits paid to residential and small farm consumers is the same as in the *pro rata* method. The rate protection for preference customers is the same as in the *pro rata* method. The only difference is that BPA's allocation proposal spreads REP benefits over a larger number of consumers, thereby better achieving BPA's goal of spreading the benefits of the FCRPS as broadly as possible.

Also, this proposed allocation methodology helps achieve one of the goals of the implementation of the REP. The proposed ASC Methodology repeats this goal of the earlier ASC Methodology, that it "should give participating utilities an incentive to minimize their costs." 73 Fed. Reg. 7270 (February 7, 2008), Section I.A. The proposed allocation allows lower ASC utilities to continue to REP receive benefits resulting in lower REP benefits for higher ASC utilities.

Finally, this is an area of discretion that BPA can employ to better meet the Recommendations of Representatives of the Investor-Owned and Certain Consumer-Owned Utilities Regarding the Residential Exchange Benefits for Customers Served by the Pacific Northwest Investor-Owned Utilities dated November 7, 2007. *See* Bliven, *et al.*, WP-07-E-BPA-52. This group of customers recommended for BPA to seek ways to more broadly distribute REP benefits among the IOUs without increasing REP benefit costs to COUs.

Q. *In the event of a utility request to exchange after rates are set and a 7(b)(3) reallocation needs to occur, how will BPA set this utility's Supplemental 7(b)(3) charge?*

A. For these eligible customers, their Supplemental 7(b)(3) charge will be the customer's average system cost minus the Base PF Exchange rate.

Q. Why is BPA setting the supplemental 7(b)(3) charge in this manner?

A. Similarly to the Targeted Adjustment Charge (TAC), setting the Supplemental 7(b)(3) charges in this way protects BPA from unexpected costs imposed by unexpected exchanging utilities. For further details on meeting BPA's REP planning horizon, *see* BPA's proposed ASC Methodology. 73 Fed. Reg. 7270 (February 7, 2008).

Q. The proposed ASC Methodology allows a utility to have more than one ASC for a particular rate period if it expects new resources to come on-line. How will this affect the utility-specific Supplemental 7(b)(3) charges?

A. If a particular exchanging utility has a new resource that begins serving retail load, or a resource is removed from serving retail load, then the ASC for that utility will change if this resource change was recognized in the ASC determination process. The change of the ASC will be effective on the date of commercial operation of the new resource, or retirement or transfer date of the removed resource. The change of the ASC will require a modification of the utility-specific Supplemental 7(b)(3) charges for all utilities participating in the REP for that year. BPA will recalculate the Supplemental 7(b)(3) charges for all utilities using the same input data as used in the final rate proposal for the relevant rate period.

Q. Why is this necessary?

A. If the ASC for the exchanging utility with a new resource were allowed to change without a change in Supplemental 7(b)(3) charges, then the REP benefits could exceed the benefit levels included in rates, resulting in higher REP benefits paid out than allowed by the 7(b)(2) rate test.

Section 6: Low Density Discount

Q. What change is proposed for the LDD section of the WPRDS?

A. The estimated cost of the LDD changed from $22.6 to $24.4 million for FY 2009.

Q. Why has the estimated cost of the LDD for FY 2009 changed?

A. The estimated cost of the LDD for FY 2009 changed because of changes in forecast loads and changes in the level of the LDD for some customers.

Section 7: Conservation and Renewable Program

Q. What change has been proposed for the Conservation and Renewable Program?

A. The Conservation Rate Credit (CRC) has been updated to remove language concerning certain CRC expenditures (specifically, those CRC expenditures which were incremental to spending that customers would have otherwise made pursuant to applicable law). BPA already made this change in the July 2007 Regional Dialogue Policy; BPA is now changing the WPRDS simply to be consistent with the Regional Dialogue Policy.

Section 8: GTA Delivery Charge

Q. What changes are proposed for the GTA Delivery Charge?

A. The GTA Delivery Charge has been updated to reflect the fact that Transmission Services has completed its rate proceeding for FY 2008-2009. Rather than refer to the Transmission Services rate proceeding as a future event, we can change the language to refer to the TR-08 determined Transmission Service Utility Delivery Charge. Therefore, the GTA Delivery Charge is now set for FY 2009.

Section 9: Other Changes to Rate Design

Q. What other changes are proposed for the WPRDS in the rate design sections?

A. All references to REP were changed to now reference the Residential Sales and Purchase Agreement (RPSA), where appropriate references to FY 2007 through FY 2009 were replaced with just FY 2009, and references to **-07 rates were updated to reference **-07R rates.

Q. Are there any other changes to rate design?

A. No, the rest of the rate design section of the WPRDS is the same as the WP-07 Final Proposal.

Q. Other than the changes to the FPS rate schedule discussed in Section 4 and the other changes discussed above are there any changes to the 2007 Wholesale Power Rate Schedules and 2007 GRSPs?

A. We have included FY 2009 in the title to clarify the application of the rate schedules and GRSPs is to FY 2009. Some minor modifications have been made to the GRSPs and rate schedules to clarify various sections, but most of these proposed modifications do not result in substantive changes to the GRSPs. Those changes that are substantive are explained in the testimony that discusses these specific topics. A red-line copy of the rate schedules and GRSPs is posted on BPA's rate case web site to make changes more evident.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY of

PAUL A. BRODIE, RAYMOND D. BLIVEN, WILLIAM J. DOUBLEDAY,

RONALD HOMENICK and BYRON G KEEP

Witnesses for Bonneville Power Administration

SUBJECT: FY 2009 COST OF SERVICE ANALYSIS AND RATE DESIGN CHANGES AND ADJUSTMENTS

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TESTIMONY of

PAUL A. BRODIE, RAYMOND D. BLIVEN, WILLIAM J. DOUBLEDAY,

RONALD HOMENICK and BYRON G KEEP

Witnesses for Bonneville Power Administration

SUBJECT: FY 2009 COST OF SERVICE ANALYSIS AND RATE DESIGN CHANGES AND ADJUSTMENTS

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Paul A. Brodie and my qualifications are contained in WP-07-Q-BPA-07.

A. My name is Raymond D. Bliven and my qualifications are contained in WP-07-Q-BPA-58.

A. My name is William J. Doubleday and my qualifications are contained in WP-07-Q-BPA-11.

A. My name is Ronald Homenick and my qualifications are contained in WP-07-Q-BPA-17.

A. My name is Byron G. Keep and my qualifications are contained in WP-07-Q-BPA-22.

Q. Please describe the purpose of your testimony.

A. The purpose of our testimony is to sponsor the Supplemental Wholesale Power Rate Development Study (WPRDS) (Study), WP-07-E-BPA-49, Section 3, and the Supplemental WPRDS Documentation (Documentation), WP-07-E-BPA-49A, Section 3. This testimony addresses BPA's Cost of Service Analysis, rate design adjustments, and the modeling of BPA's rate development.

Q. How is your testimony organized?

A. Our testimony is organized in four sections. Section 1 states the purpose of our testimony. Section 2 describes the COSA, including subsections on the Program Case and the 7(b)(2) Case, and changes to the Rate Analysis Model (RAM2007) COSA logic.

Section 3 describes changes to rate design and ratemaking adjustments, with subsections on: (a) modeling the Low Density Discount (LDD); (b) modeling the Conservation Rate Credit (CRC); and (c) modeling rate mitigation for customers with seasonal loads.

Section 4 describes the modeling of the rate development process, with subsections on: (a) modeling the Rate Design Step; (b) modeling the Slice Separation Step; and (c) modeling the Slice product cost.

Section 2: Cost of Service Analysis (COSA): Program Case and 7(b)(2) Case

Q. What are the Program Case and the 7(b)(2) Case?

A. The section 7(b)(2) rate test involves the projection and comparison of two sets of wholesale power rates for the general requirements loads of BPA's public body, cooperative, and Federal agency customers. *See* Supplemental Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50 and Keep, *et al.*, WP-07-E-BPA-68. The two sets of rates are: (1) a set for the rate test period (FY 2009) and the ensuing four years (FY 2010-2013) assuming that section 7(b)(2) of the Northwest Power Act is not in effect (this set is known as the Program Case rates); and (2) a set for the same period taking into account the five assumptions listed in section 7(b)(2) (this set is known as the 7(b)(2) Case rates). The 7(b)(2) Case rates are modeled the same as the Program Case rates except for the five assumptions listed in section 7(b)(2).

Q. What is the purpose of the COSA section in the RAM?

A. The COSA allocates the test period generation revenue requirements that are determined in the Supplemental Revenue Requirement Study, WP-07-E-BPA-46, to BPA's customer classes. The COSA allocates the test period generation revenue requirements among classes of service based on statutory direction and the principle of cost causation. The relative use of resources, services, or facilities among customer classes is identified, and costs generally are allocated to customer classes in proportion to each class's use. Cost allocation also is based on the priorities of service from resource pools to rate pools provided in section 7 of the Northwest Power Act.

Q. *How were generation revenue requirements assigned to the resource pools in the COSA?*

A. Consistent with past practice, costs were assigned to the resource pools primarily by direct identification and consistent with the rate development requirements of the Northwest Power Act. Exceptions are net interest expenses and planned net revenues, which were first functionalized between conservation and the remainder of generation by the use of equivalent annual costs (annual mortgage-type payments). The generation portions were then allocated among Federal Base System (FBS) Hydro, Fish and Wildlife, and BPA generation programs based on average net investment.

Q. *Is the assignment of generation revenue requirements to the resource pools reflected in the Program Case and 7(b)(2) Case?*

A. Yes. The assignment of generation revenue requirements to the resource pools is reflected in the Program Case revenue requirements for all years of the 7(b)(2) rate test (FY 2009–2013) and in the 7(b)(2) Case revenue requirements for all years of the 7(b)(2) rate test (FY 2009–2013).

Q. *Were the 7(b)(2) Case revenue requirements developed on the same basis as in previous rate cases?*

A. Yes. The 7(b)(2) Case revenue requirements reflect the Program Case revenue requirements with the required exclusions of costs associated with the Residential Exchange Program (REP), energy conservation, and the new resources acquired under the authority of the Northwest Power Act. Repayment studies for the 7(b)(2) Case revenue requirements also exclude those costs.

Q. *How did BPA address risk mitigation in the Program Case revenue requirements?*

A. For the FY 2009 rate period, BPA has not included any additions to revenue requirements for Planned Net Revenues for Risk (PNRR) in the Program Case revenue requirements. In addition, no additional funds were required to make up the difference between (1) non-cash expenses included in revenue requirements and (2) the cash requirements for amortization of bonds and appropriations and irrigation assistance (Minimum Required Net Revenues (MRNR)) for FY 2009. In the Program Case generation revenue requirements, there were years during the rate test period when MRNR additions were required to satisfy cash requirements for planned amortization and irrigation assistance payments. *See* Documentation, WP-07-E-BPA-49A, Section 2, Table COSA06.

Q. *If PNRR had been needed for FY 2009 and had been included in the COSA tables, how would BPA determine the proper amount of PNRR?*

A. The PNRR value used in the COSA06 tables is the result of an iterative process between the RAM2007, the RiskMod model, and the ToolKit model (including the NORM model results). The iteration is initiated with a seed value for PNRR in the COSA 06 tables of the RAM2007. The resultant rates and revenue requirement data are used in RiskMod to produce probability distributions. These distributions are then used in the ToolKit to produce a new PNRR value and annual ending cash reserve amounts for new COSA 06 tables. The iterations are complete when the difference between the new PNRR value and the previously calculated value is less than $1 million per year.

Q. *During the iteration process mentioned above, which rates from RAM2007 are used in the RiskMod?*

A. RAM2007 produces rates in its Rate Design Step and its Slice Product Separation Step, all of which are, in turn, used in the RiskMod. These two major rate calculation steps are more fully discussed in Section 4 of this testimony. A PNRR iterative process is done using the final non-Slice Product rates produced by the last of the major ratemaking steps, the Slice Product Separation Step.

Q. *Why is it appropriate to use the Slice Product Separation Step rates as the basis for determining the PNRR level?*

A. In the Rate Design Step, the PF Preference rate pool includes the loads of all PF Preference products. The Slice Product Separation Step separates the Slice product firm loads, revenue credits, and allocated costs from the non-Slice product PF Preference loads, revenue credits, and costs. Purchasers of the PF Slice product assume the risks mitigated by PNRR. The PNRR that BPA adds to its revenue requirement is recovered by BPA's non-Slice product rates. Therefore, the non-Slice product PF Preference rate calculated in the Slice Product Separation Step is the appropriate PF rate to use in the risk iteration process that determines the level of PNRR. For additional RiskMod, NORM, and ToolKit information, *see* Normandeau, *et al.*, WP-07-E-BPA-73.

Q. *How did you address risk mitigation in the 7(b)(2) Case revenue requirements?*

A. As in previous rate cases, the 7(b)(2) Case revenue requirements reflect the same treatment of risk mitigation as in the Program Case. During the FY 2009 rate period, the 7(b)(2) Case revenue requirements produce annual cash flows that are identical to those of the Program Case revenue requirements. In the out-years, the 7(b)(2) Case revenue requirements are based on total expenses and any net revenues needed to satisfy cash requirements for amortization and irrigation assistance payments, as was done in the Program Case revenue requirements.

Section 3: Rate Design Changes and Adjustments

Section 3.1: Modeling the Low Density Discount (LDD)

Q. Has the modeling of the LDD changed in RAM2007 for the Supplemental Proposal?

A. No. In RAM2007, to avoid adverse impacts on retail rates of BPA's purchasers with low system densities, the LDD, to the extent appropriate, are applied to BPA's rates for such purchasers. The costs and the benefits associated with the LDD are limited to the PF Preference rate class. In RAM2007, the costs associated with the LDD were allocated to the PF rate pool in the initial cost allocation step at the beginning of the ratemaking process.

Section 3.2: Modeling the Conservation Rate Credit Costs

Q. Has the modeling of the Conservation Rate Credit (CRC) costs changed in RAM2007 for the Supplemental Proposal?

A. No. In RAM2007, the costs associated with the CRC are included in BPA's revenue requirement and enter the ratemaking process at the very beginning by including the CRC costs within the conservation line of each year's COSA Table. *See* WPRDS Documentation, WP-07-E-BPA-49A, COSA 06 tables.

Section 3.3: Modeling Rate Mitigation for Customers with Seasonal Loads

Q. Is seasonal and irrigation rate mitigation modeled the same in RAM2007 for the Supplemental Proposal?

A. Yes. Rate mitigation is targeted to PF Preference rate class customers with heavy summer seasonal loads that faced adverse rate impacts from BPA's rate design. The costs and the benefits associated with this rate mitigation are limited to the PF Preference class. In RAM2007, the costs associated with the rate mitigation were allocated to the PF rate pool in the initial cost allocation step at the beginning of the ratemaking process.

Section 4: Rate Development Modeling

Section 4.1: RAM2007

Q. How is RAM2007 organized?

A. RAM2007 has two main steps: a Rate Design Step and a Slice Separation Step.

Section 4.2: Rate Design Step

Q. Please briefly describe the Rate Design Step in RAM2007.

A. The RAM2007 Rate Design Step follows statutory rate directives by determining the costs associated with the three resource pools (FBS resources, Exchange resources, and new resources) used to serve load and then allocating those costs to the rate pools (PF, IP, and NR). After the initial allocation of costs, the Northwest Power Act requires that some rate adjustments be made, such as those described in section 7(b) and section 7(c) of the Act. RAM2007 performs these rate adjustments, including the 7(b)(2) rate test, in its Rate Design Step. The Rate Design Step within RAM2007 concludes with the calculation of the Rate Design Step rates.

Section 4.3: Slice Separation Step

Q. Please provide a brief description of the Slice Separation Step.

A. In the Rate Design step, costs were allocated to the various rate pools, including the PF Preference rate pool that contained all firm PF Preference load. The Slice Separation Step separates out the PF Slice product revenues, revenue credits, and firm loads from the overall PF Preference rate pool, leaving the costs that must be covered by the remaining non-Slice product PF Preference load through posted PF Preference energy, demand, and load variance charges. In addition, an adjustment to the costs allocated to the non-Slice product PF Preference pool is made for the amount the Administrator decides to apply against the IOU REP Lookback Amounts for the rate period, and/or if there is an exchanging utility that is repaying their deemer balance during the rate period. For FY 2009, the amount of these adjustments is $37.1 million. *See* WPRDS Documentation, WP-07-E-BPA-49A, Table 2.6.2, SLICESEP 01 and the testimony of Marks, *et al.*, WP-07-E-BPA-62.

Q. Have changes been made in the Slice Separation Step of the RAM2007 used in the FY 2009 portion of the WP-07 Supplemental Proposal?

A. Yes. There are two changes that have been made to the RAM2007 Slice Separation Step.

Q. What is the first change to the Slice Separation Step?

A. The first change is that the portion of secondary energy revenue assumed to be marketed by the Slice product customers is removed during the Slice Separation Step. This first change is necessary because we now use the total value of secondary energy sales as a credit to loads served by the FBS resources. Previously, we credited only that portion of the secondary energy sales value that was associated with the secondary energy that BPA sold into West Coast energy markets. Because the Rate Design Step allocates the costs of FBS resources to all firm PF loads, including Slice product loads, we now credit the total value of secondary sales revenue to those same loads. This is done even though the Slice product customers are expected to purchase about 22.6 percent of the total secondary produced by the FBS resources. This matching of costs and benefits follows general ratemaking principles. As a consequence of the Slice portion of FCRPS secondary having been allocated to the PF Preference class in the Rate Design Step, that amount of secondary revenue credit must be removed during the Slice Separation Step. *See* WPRDS Documentation, WP-07-E-BPA-49A, Table 2.6.2, SLICESEP 01.

Q. What is the second change made to the Slice Separation Step?

A. As part of the Supplemental Proposal, BPA is determining Lookback Amounts that will be used to reduce future REP benefits over time. *See* Lookback Study, WP-07-E-BPA-44, Section 15. In the Rate Design Step, BPA's rates are set to collect the calculated net REP benefit costs. The Slice Separation Step now adjusts the non-Slice PF rate for any REP benefits that have been applied to the Lookback balance. In addition, if the Rate Design Step rates recover REP benefits that can be applied to reduce an exchanging utility's deemer balance, an adjustment for that eventuality is now in the Slice Separation Step. For FY 2009, the amount of these adjustments is $37.1 million. *See* WPRDS Documentation, WP-07-E-BPA-49A, Table 2.6.2, SLICESEP 01 and Marks, *et al.*, WP-07-E-BPA-62.

Section 4.4: Modeling the Slice Product

Q. How is the Slice product modeled in RAM2007?

A. RAM2007 includes a Slice Cost worksheet that estimates the cost per month of a 1-percent Slice of the BPA system. This worksheet lists the components of the Slice revenue requirement, including the net cost of system augmentation, and excluding the cost of balancing power purchases and PNRR. The cost per month of the Slice product is an estimate for initial bills and will be trued up to actuals after the close of the fiscal year. *See* Lee, *et al.*, WP-07-E-BPA-74.

Section 5: Changes in the Rate Analysis Model

Section 5.1: RAM2007 Models

Q. Why did you develop RAM2007 to conduct the 7(b)(2) rate test and to prepare rates for the WP-07 Supplemental Proposal?

A. The need for greater efficiency and flexibility in rate analysis prompted us to develop RAM2007. Although RAM2002 was developed specifically for the five-year WP-02 rate period and the associated nine-year 7(b)(2) test period, RAM2007 was developed to provide the capability to forecast rates over a ten-year period. In addition, whereas RAM2002 was designed to accurately model the WP-02 rate case assumptions, RAM2007 accommodates different scenarios and forecasts 7(b)(2) rate test triggers and rates for the 2007-2009, 2009, 2010-2011, and 2012-2013 rate periods (assuming BPA moves to two-year power rate periods in the future).

Q. Please briefly describe RAM2007.

A. RAM2007 is a large Excel spreadsheet model that is automated with Visual Basic macros. RAM2007 is intended to be more operator-friendly than RAM2002.

Q. Please describe how RAM2007 is more operator-friendly.

A. RAM2007 is operated from a pull-down menu and explicitly shows the rate results after each ratemaking step. RAM2007 automatically determines which of the possible exchanging utilities will be exchanging as the unbifurcated PF and PF Exchange rates are developed. RAM2002 relied on inspection by the analyst to determine the number of utilities participating in the REP. RAM2007 calculates the PF Slice product cost for each year and incorporates those data in the calculation of the PF Preference rate. Because Slice contracts had not yet been signed at the time of the WP-02 rate case, RAM2002 did not use Slice product cost data in the calculation of rates.

Q. *Is the RAM2007 model you used to conduct the Supplemental Proposal 7(b)(2) rate test also used to develop the rates for the Supplemental Proposal?*

A. Yes. The forecasts and policy assumptions used in the Program Case of the 7(b)(2) rate test are also used in the calculation of proposed rates for the Supplemental Proposal. RAM2007 conducts the 7(b)(2) rate test as just one of several ratemaking steps to calculate rates. Although RAM2007 grouped three years (36 months) of costs, credits, and sales together to calculate average rates for the original three-year rate period for the WP-07 Final Proposal, it now uses a one-year rate period (FY 2009) for the Supplemental Proposal.

Section 5.2: Principal Modeling Changes

Q. *Have you made any changes to its rate development modeling for the Supplemental Proposal?*

A. Yes. There are four principal changes to the RAM2007 models:

(1) The RAM2007 model used in the WP-07 Final Proposal had a Subscription Step to allocate REP Settlement Agreement costs. The RAM2007 model used in the Supplemental Proposal does not use the Subscription Step. In the Supplemental Proposal, rates are set to collect the cost of REP benefits in the Rate Design Step.

(2) The composition of the 7(b)(2) Case resource stack was changed. *See* Keep, *et al.*, WP-07-E-BPA-68.

(3) BPA changed the way it models the section 7(b)(3) reallocation of the 7(b)(2) PF Preference rate protection amount. *See* Keep, *et al.*, WP-07-E-BPA-68.

(4) The amount of the secondary revenue credit applied to rates in the Rate Design Step has been increased. This is explained in greater detail below.

Section 5.2.1: Elimination of Subscription Step

Q. Is the stepped ratemaking (Rate Design Step and Slice Separation Step) similar to that used in RAM2007 for the WP-07 Final Proposal?

A. Yes, except that RAM2007 for the WP-07 Final Proposal developed rates in a three-step process and now one of those steps, the Subscription Step, has been removed. In the WP-07 Final Proposal, the Program Case rates for the 7(b)(2) rate test were calculated in the Rate Design Step using all costs, including a forecast of gross exchange costs for the IOUs. BPA then conducted a Subscription Step to reallocate costs arising from the REP Settlement Agreements. Then the Slice Separation Step was applied.

Q. Why was the Subscription Step removed?

A. The Subscription Step reallocated costs arising from the REP settlements. The costs of the REP settlements have been removed from the revenue requirement. *See* Bliven, *et al.*, WP-07-E-BPA-52. Therefore, the Subscription Step has been removed from RAM2007.

Section 5.2.2: Secondary Revenue Credit Modeling Changes

Q. Have you changed the way it models the secondary energy revenue credit for this Supplemental Proposal?

A. Yes. In the WP-07 Final Proposal, BPA used only the non-Slice portion (77.37 percent) of the secondary energy produced by the Federal Columbia River Power System (FCRPS) in the calculation of rates. The non-Slice portion is the amount of revenue that BPA forecasts it will earn from the sale of 77.37 percent of the FCRPS secondary energy in the West Coast electric markets. In addition to these sales, the other 22.63 percent of the secondary produced by the FCRPS is sold as a part of the Slice product at the

PF Slice rate. BPA now proposes using revenues as if all secondary energy was sold in the electric markets in the calculation of rates in the Rate Design Step ratemaking.

Q. Why do you now use the total market value of secondary energy as a revenue credit in the Rate Design Step?

A. In the Rate Design Step, the PF rate pool includes the firm portion of the Slice product sales. Therefore, it is more proper from a general ratemaking prospective to include the a secondary revenue credit produced by the FCRPS in the rate pool that is paying the costs of the FCRPS at this point in the ratemaking process, the total PF rate pool. After the Rate Design Step, in the Slice Separation Step, the Slice product, costs, loads, and secondary revenue credit are removed from the PF Preference load pool.

Q. What is the secondary revenue credit forecast for FY 2009?

A. BPA expects the total secondary energy would produce about $743.9 million in revenues in FY 2009 if sold into the electric markets. Of the total revenue forecast of $743.9 million, 22.63 percent or about $168.3 million will instead be sold to BPA's Slice product customers at the PF Slice rate producing no incremental revenue. The remaining $575.6 million is forecast to be marketed by BPA and is a revenue credit to non-Slice rates. *See* WPRDS Documentation, WP-07-E-BPA-49A, Table 2.5.3, (RDS 11).

Section 5.3: Additional Modeling Changes

Q. Have other changes been made to the RAM2007 used in the Supplemental Proposal?

A. Yes. Some modeling changes have been made to the most current version of RAM2007. These changes were made to either correct errors in the calculations or to make the calculations more transparent. These changes are relatively minor.

Section 6: FYs 2009 Results: Projected Rates and Net Cost of the REP

Q. Please describe the results of the recalculation of the Supplemental Proposal rates for FY 2009 after the changes outlined above.

A. In the Supplemental Proposal, BPA is recalculating the PF Exchange rate that the level of benefits the exchanging utilities will receive from the REP for FY 2009. The rate modeling described above results in an average PF Preference rate of 26.15 mills/kWh; an average PF Exchange rate of 42.28 mills/kWh; and a 7(b)(2) rate test trigger of 5.2 mills/kWh for FY 2009. The PF Exchange rate, when applied to the forecast IOU ASCs for FY 2009, produced an IOU REP benefit (net cost) amount of about $250 million for FY 2009 (before adjustments to apply a portion of these REP benefits to the Lookback Amount). *See* FY 2009 WPRDS Documentation, WP-07-E-BPA-49A, Table 2.9.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY of

W. MICHAEL MCHUGH, RANDY RUSSELL, and ROBERT YOUNG

Witnesses for Bonneville Power Administration

SUBJECT: SUPPLEMENTAL RESIDENTIAL EXCHANGE AVERAGE SYSTEM COST AND LOAD FORECASTS FOR FY 2009

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TESTIMONY of

W. MICHAEL MCHUGH, RANDY B. RUSSELL, and ROBERT YOUNG

Witnesses for Bonneville Power Administration

SUBJECT: SUPPLEMENTAL RESIDENTIAL EXCHANGE AVERAGE SYSTEM COST AND LOAD FORECASTS FOR FY 2009

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is W. Michael McHugh and my qualifications are contained in WP-07-Q-BPA-65.

A. My name is Randy B. Russell and my qualifications are contained in WP-07-Q-BPA-47.

A. My name is Robert Young and my qualifications are contained in WP-07-Q-BPA-69.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to describe the data sources, models and assumptions we used to develop the 2009 through 2013 forecast of Average System Costs (ASCs) and loads for utilities that may participate in the Residential Exchange Program (REP). This testimony sponsors Section 8, *2009 ASC and Exchange Load Forecast*, of the Supplemental Wholesale Power Rate Design Study (WPRDS), WP-07-E-BPA-49, and Supplemental WPRDS Documentation, WP-07-E-BPA-49B

Q. How is your testimony organized?

A. Our testimony is organized in eleven sections. Section 1 outlines the purpose of our testimony. Section 2 describes the REP. Section 3 describes the process for determining the Average System Cost Forecasts and contains a brief description of the major differences between the 1984 ASC Methodology (ASCM), 18 C.F.R. § 301.1, and the proposed 2008 ASC Methodology, 73 Fed. Reg. 7270 (February 7, 2008). Section 4 identifies the potential exchanging utilities. Section 5 describes the data sources used in the ASC forecasts. Section 6 describes the methodology and functionalization assumptions used to forecast FY 2009 ASCs. Section 7 presents the base year (2006) exchangeable costs and ASCs. Section 8 presents the forecast of the exchanging utility loads. Section 9 presents the escalation rate and price forecasts used in the analysis. Section 10 presents the forecast ASCs. Section 11 describes changes to forecast ASCs for the final rate proposal.

Section 2: Description of the Residential Exchange Program (REP)

Q. What is the Residential Exchange Program?

A. The Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) created the REP to provide residential and small farm customers of Pacific Northwest (regional) utilities a form of access to low-cost Federal power. 16 U.S.C. § 839c(c). Under the Northwest Power Act, BPA "purchases" power from each participating utility at the average system cost of that utility's resources. BPA then offers, in exchange, to "sell" an equivalent amount of electric power to the utility at BPA's Priority Firm Exchange (PF Exchange) rate. The amount of power purchased and sold is no greater than the qualifying residential and small farm load of each utility participating in the REP. The Northwest Power Act requires that the net benefits of the REP be passed on directly to the residential and small farm customers of the participating utilities.

Q. Does the REP involve a conventional purchase and sale of power?

A. No. Under the normal implementation of the REP, no actual power is transferred either to or from BPA. Because the amounts of power purchased and sold are the same, the "exchange" is a "paper" transaction where BPA provides the participating utility cash payments that represent the value difference between power "purchased" by BPA and the less expensive power "sold" to the participating utility.

Section 3: Process for Determining Average System Cost Forecasts for FY 2009

Q. What is the process for determining ASCs for 2009?

A. Each exchanging utility's ASC will be initially determined by the Administrator in accordance with the proposed 2008 ASC Methodology (ASCM). The ASCM is an administrative rule developed by BPA in consultation with its customers that sets out the procedures and the process to calculate an ASC. The proposed 2008 ASCM is currently being developed in a separate public consultation process. (*See* Proposed Methodology for Determining the Average System Cost of Resources for Electric Utilities Participating in the Residential Exchange Program Established by Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act.) *See* Proposed 2008 ASCM – *www.BPA.gov/corporate/finance/ASCM*. After conducting an expedited review process and determining ASCs under the Proposed 2008 ASCM outside the WP-07 Supplemental Proceeding, BPA will later review the ASC determinations to ensure they comply with the ASCM as approved by FERC, whether on an interim basis or a final basis.

Q. Since the public consultation process is just beginning, how did you determine ASCs for the Supplemental Proposal?

A. BPA is not determining ASCs in this Supplemental Proposal. Rather, BPA is forecasting ASCs for use in the ratesetting process. The forecast ASCs are based on BPA's interpretation of the proposed ASCM, using data sources and procedures specified by the proposed ASCM. Concurrent with the consultation process to establish a new ASCM, BPA will determine utilities' ASCs in an expedited review process. At the conclusion of the expedited review process, the ASCs determined in that process will be incorporated into BPA's final Supplemental Proposal.

Q. What are the major differences between the 1984 ASCM and the proposed 2008 ASCM?

A. There are five major changes in the proposed 2008 ASCM that affect the level of utility ASCs. The first major change is the source of data for the ASC determinations. Under the 1984 ASCM, BPA used IOU state public utility commission data to determine ASCs (known as the jurisdictional approach). BPA has proposed moving away from a jurisdictional approach to a FERC Form 1 basis. The FERC Form 1 is an annual filing that all IOUs are required to file with the Federal Energy Regulatory Commission (FERC) that contains the utility's financial information. Second, BPA has proposed one ASC determination per utility for each rate period rather than a new ASC determination in each jurisdiction each time the utility changes its retail rates. Third, BPA proposes to include return on equity in the ASC at the level approved in the exchanging utility's most recently approved rate order from its regulatory commission. Fourth, BPA proposes to allow imputed Federal income taxes at the marginal Federal income tax rate. Fifth, BPA proposes to allow all transmission plant and related expenses. In addition, BPA is proposing numerous other changes to the proposed 2008 ASCM. Comments or questions about these changes should be addressed to the ASCM consultation process. BPA encourages parties to refer to BPA's ASC Consultation process for further information. *See* www.BPA.gov/corporate/finance/ASCM.

Q. How do you propose to forecast the exchanging utilities' ASCs?

A. Essentially, a utility's ASC is the sum of a utility's production and transmission costs (Contract System Costs) divided by the utility's system load (Contract System Load). We begin by determining a base year ASC for each utility. To establish a base year ASC, BPA proposes to compile each utility's system costs and system loads, as reported by the utility either in their most recent FERC Form 1 for investor own utilities (IOUs) or from similar sources for the consumer-owned utilities (COUs). These costs and loads will then be adjusted for items explicitly excluded from ASC by the proposed ASCM. Finally, the base year costs are escalated to the period encompassing the rate period for which the ASC will be used, called the exchange period.

Q. *What are contract system costs?*

A. Contract System Costs are the utility's cost of resources, specifically, the costs for production resources and the transmission of those resources, including power purchases and conservation measures. *See* proposed 2008 ASCM at www.BPA.gov/corporate/finance/ASCM

Q. *What are contract system loads?*

A. Contract System Loads are total regional retail loads, including distribution losses, served by an exchanging utility. The region is defined by section 3(14) of the Northwest Power Act. 16 U.S.C. § 839a(14).

Q. *What contract system costs and loads are explicitly excluded from ASCs?*

A Section 5(c)(7) of the Northwest Power Act lists the costs and loads that cannot be included in an exchanging utility's ASC. 16 U.S.C. § 839c(c)(A), (B), (C). They include: the costs to serve a new large single load (NLSL); the costs to serve extra-regional load that occurs after December 5, 1980; and the costs of a generating facility terminated prior to commercial operation.

Q. *How do you determine production and transmission-related costs to be included in a utility's ASC?*

A. Because only production and transmission costs are considered exchangeable costs, all costs must be functionalized to determine if they are related to production, transmission, or distribution. Functionalization is a process that allocates costs to production, transmission, or distribution. For the majority of the costs, the functionalization is clear. In other cases, the proposed 2008 ASCM directs BPA to functionalize costs based on certain ratios, *e.g.*, *pro rata* on labor costs assigned to the three functions (production, transmission, and distribution).

Q. *What are the sources of the cost data you propose to use to determine a utility's base year ASC?*

A. The proposed 2008 ASCM directs the exchanging IOUs to use FERC Form 1, Results of Operation or similar reports filed with state public utility commissions, and state commission approved rates of return. For potential exchanging COUs, BPA has proposed alternative sources. For the forecast used in the Supplemental Proposal, we used the COUs' annual reports. Such data provide the starting point for BPA's determination of the ASC for each utility participating in or potentially participating in the REP.

Q. *What process did you use to develop individual utility ASC forecasts for the 2009 through 2013 period for the Supplemental Proposal?*

A. We used a two-step process. First, we computed a 2006 base year ASC estimate for each utility. The base year ASCs were calculated from the IOUs' 2006 FERC Form 1 filings, utility annual results of operations filings, commission authorized return on equity, and COUs' annual reports. This information was loaded into the new 2008 ASC Cookbook model (2008 Cookbook) to calculate the 2006 base year ASC for each utility. The 2006 production and transmission costs from the 2008 Cookbook model were then transferred into the ASC Forecast Model to escalate individual utility base year ASCs for each year from 2007 through 2013. The 2007 and 2008 ASCs are not used in this process, but the 2009 ASC is used to estimate exchange costs for the 2009 rate period. The 2010 through 2013 utility ASCs are used as part of the section 7(b)(2) rate test.

Q. *Did you use the same computer model used in the WP-07 Final Proposal for developing the 2009 through 2013 forecast of individual utility ASCs?*

A. No. We developed two new Excel-based models. First, BPA developed a new ASC Cookbook model (2008 Cookbook) that is based on the proposed 2008 ASCM to develop a base year ASC for each exchanging utility. The base year ASC for each utility is an ASC using 2006 data and the proposed 2008 ASCM. We then developed a separate new model to escalate each utility's 2006 base year ASC as proposed in the 2008 ASCM for the 2009 through 2013 period (ASC Forecast Model).

Q. What is the 2008 Cookbook?

A. The 2008 Cookbook is an Excel based modeling tool that automatically separates utility financial information into exchangeable cost categories (generally, production and transmission), and non-exchangeable cost categories (generally distribution) based on the rules set forth in the proposed 2008 ASCM. *See* WPRDS Documentation, WP-07-E-BPA-49B. The 2008 Cookbook uses the IOU FERC Form 1 filings and allows for detailed review of production and transmission costs.

Q. What is the ASC Forecast Model?

A. The ASC Forecast model is also an Excel model that uses FERC Form 1 data and implements BPAs proposed 2008 ASCM. The ASC Forecast Model is discussed in detail in WPRDS, WP-07-E-BPA-49, Section 8.

Section 4: Potential Exchanging Utilities

Q. How did you determine which utilities to include in the 2009 through 2013 forecast of ASC?

A. We assumed that all six of the regional IOUs that previously participated in the REP will sign new Residential Purchase and Sale Agreements (RPSAs) and participate in the REP. For these six IOUs, we evaluated costs and loads, and forecast individual ASCs for the 2009 through 2013 period as previously described.

Q. Were any COUs evaluated in detail?

A. Yes. We forecast that three regional COUs may be eligible to sign RPSAs and participate in the REP. We forecast that Benton County PUD, Grays Harbor County PUD and Snohomish County PUD are three regional COUs that could potentially participate in the REP. We evaluated their costs and loads, and forecast individual ASCs for the 2009 through 2013 period using public data sources.

Section 5: Data Sources

Q. Do you propose to use the same data source for both IOUs and COUs?

A. No. We must use different data sources for the ASC determinations for the IOUs and COUs because COUs are not required to prepare and submit Form 1 filings with FERC or results of operations to state commissions.

Q. What data sources were used to forecast the IOUs' base year ASCs?

A. The primary source of data for the IOUs is the individual utility 2006 FERC Form 1 filings. In addition, BPA also used data and information from annual results of operations filings some utilities make to their state regulatory commissions, and state public utility commission rate orders. The FERC Form 1 is a required annual submittal by IOUs to FERC of financial, operating, and load information for the previous calendar year. Additionally, we used some information from 2002-2006 FERC Form 1 filings to determine the quantity of purchased power and sales for resale used in the forecast of individual utility ASCs for the 2009 through 2013 period.

Q. Will the FERC Form 1 be the sole source of data for the base year ASCs?

A. No. The base year ASCs are being constructed in accordance with the 2008 ASCM, which has a new form that will be used to calculate individual IOU ASCs for FY 2009. Though this form relies primarily on FERC Form 1 data, in certain areas BPA will need additional information not available on the FERC Form 1 to make an accurate base year ASC determination. BPA intends to request more information from the exchanging utilities during the review of the individual utility ASC filings in the separate ASCM public process. We will use the results of the consultation process, including any additional data provided by the utilities, to determine the final base year ASCs.

Q. What data sources were used to forecast the COUs' base year ASCs?

A. The primary source of data for the COUs is the individual utility 2006 annual report.

Section 6: ASC Methodology and Functionalization Assumptions for FY 2009

Q. What ASCM did you use to prepare the utility ASC forecasts for the 2009 through 2013 period?

A. We used the proposed 2008 ASCM to prepare the ASC forecasts used to develop our testimony and exhibits. The proposed ASCM contains a printed version of the proposed 2008 Cookbook. The template lists the functionalization of all FERC Form 1 accounts used in the development of our ASC forecast.

Q. Why did you use the 2008 ASCM in the FY 2009 forecast?

A. This is the methodology that we believe will be in effect during the FY 2009 rate period. To the extent the 2008 ASCM changes as a result of the consultation process, we intend to reflect such changes in the final ASC calculations.

Q. Which accounts require direct functional analysis?

A. Table 1 lists the accounts that will require direct analysis by the exchanging utilities. PacifiCorp has a number of accounts that the other utilities do not. These accounts are identified by the column labeled PacifiCorp Specific.

Table 1
<u>Direct Analysis Accounts</u>

Account Description	PacifiCorp Specific	Direct Functionalization Required in Actual Filings	Method
Intangible Plant - Franchises and Consents		DIRECT	PTD
Intangible Plant - Miscellaneous		DIRECT	PTD
Other Tangible Plant (Mining)	PAC	DIRECT	DIR-P
Amortization of Intangible	PAC	DIRECT	DIR-D
Amortization Electric Plant. Acquisition. Adjust	PAC	DIRECT	DIR-P
Amortization of Plant held for fut. Use	PAC	DIRECT	DIR-D
Capital Lease Common	PAC	DIRECT	PTD
Accumulation Provision for Depreciation, Amortization, & Depletion (In-Service Depreciation: Common Plant)		DIRECT	PTD
Accumulation Provision for Depreciation, Amortization, & Depletion (Amortization of Other Utility Plant: Electric)		DIRECT	PTD
Amortization of Plant Acquisition Adjustments (Electric)		DIRECT	DIR-P
(Utility Plant) In Service (Classified) COMMON		DIRECT	PTDG
(Utility Plant) Completed Construction - Not Classified		DIRECT	PTD
Acquisition Adjustments (Electric)		DIRECT	DIR-P
Other Investment		DIRECT	DIR-D
Prepayments (165)		DIRECT	PTD
Other Regulatory Assets (182.3)		DIRECT	DIR-D
Miscellaneous Deferred Debits (186)		DIRECT	DIR-D
Deferred Losses from Disposition of Utility Plant (187)		DIRECT	DIR-D
Other Deferred Credits (253)		DIRECT	DIR-D
Other Regulatory Liabilities (254)		DIRECT	DIR-D
Oregon Public Purposes Charge		DIRECT	DIR-P
All Taxes other than Federal		DIRECT	DIRECT
(456) Other Electric Revenues		DIRECT	PTD

Source: WPRDS Documentation, WP-07-E-BPA-49B, Section 8: 2009 ASC and Exchange Load Forecast

Q. What is meant by direct analysis?

A. For a direct analysis the utility examines the functional nature of the account and the associated costs rather than using a predefined ratio. The exchanging utility then needs to provide documentation regarding how costs are incurred and allocated between production, transmission and distribution.

Q. How did you deal with the accounts that required direct analysis in the forecast?

A. In most cases, the FERC Form 1 does not contain enough detail for us to make a direct analysis of these accounts specified in the proposed ASCM as needing more information. In these cases, we chose a functionalization that we believed best represented how the account's costs would be functionalized among production, transmission, distribution and, in some cases, general. These functionalizations, however, may change as a result of the consultation process.

Q. Did you perform a direct analysis on any of the accounts that require direct analysis?

A. Yes. We performed a direct analysis on taxes other than income taxes and the Oregon Public Purpose Charge (OPPC).

Q. How did you treat taxes other than federal income taxes?

A. BPA functionalized all other taxes based on the ratios specified in the 2008 ASCM except in those cases where BPA could directly functionalize taxes to production or transmission. For this study we adopted the direct functionalization of taxes that was used in Lookback Study WPRDS Documentation, WP-07-E-BPA-44A, Section 11**.**

Q. How did you treat the Oregon Public Purpose Charge?

A. We have not had the opportunity to review and audit the costs and programs of the organizations that receive OPPC funds in order to determine the portion of the costs that are includable in ASCs. Until that review occurs, BPA has assumed that 70% of the OPPC would be exchangeable. This is the same treatment of the OPPC charge BPA proposed in Lookback portion of this proceeding. *See* Lookback Study WPRDS Documentation, WP-07-E-BPA-44A, Section 11. For the final Supplemental Proposal, a direct analysis will be performed to determine the amount of costs that will be exchangeable.

Q. Were any adjustments made to the FERC Form 1 data of any utility?

A. Yes. We adjusted PacifiCorp's FERC Form 1 data to limit the data to its regional loads and resources.

Q. Please explain why these adjustments were made.

A. The Northwest Power Act and the proposed 2008 ASCM require that exchanging utilities include only costs incurred to serve regional loads in their ASC filings.

PacifiCorp operates both inside and outside the region. PacifiCorp's FERC Form 1 is based on its total system, including costs and loads outside of the region. We adjusted PacifiCorp's 2006 FERC Form 1 filing to exclude out-of-region costs and loads using information from annual results of operations filings PacifiCorp makes with its state regulatory commissions.

Q. *How did you allocate PacifiCorp's total system costs to the PNW?*

A. PacifiCorp's multi-jurisdictional nature has resulted in the state utility commissions jointly developing a system of cost allocation between the states known as the Inter-Jurisdictional Cost Allocation Protocol (JCAP). This protocol allocates PacifiCorp's total electric operations proportionately to each of the states in which it serves load at regulated rates. This allocation system ensures that customers in each of its jurisdictions pay only their proportionate share of PacifiCorp's total system costs and that PacifiCorp will recover its total costs of serving its jurisdictional load.

Q. *What process did you use to ensure that the allocation of costs from PacifiCorp's FERC Form 1 contains only costs associated with PacifiCorp's regional jurisdictions?*

A We used factors from the JCAP and PacifiCorp's annual results of operation filings to its state regulatory commissions for the years 2002-2006. *See* Lookback Study WPRDS Documentation, WP-07-E-BPA-44A, Section 11. We matched the JCAP regional allocation factors to the corresponding FERC Form 1 accounts used in the 2008 ASC Cookbook model. The total costs in each account were then multiplied by the regional allocation factors to produce PacifiCorp regional costs by state. The 2008 ASCM proposes that multi-jurisdictional utilities file an aggregate regional ASC. We therefore combined PacifiCorp's Idaho, Washington, and Oregon allocated costs to get a regional combined ASC. We used PacifiCorp's system generation (SG) allocation factor to allocate the Purchased Power and Sales-for-Resale costs and revenues to the Northwest. *See* Supplemental WPRDS Documentation, WP-07-E-BPA-49B.

Q. *What methodology did you use to determine the rate of return on rate base for the IOUs and the COUs?*

A. For the IOUs, we used the most recently authorized rate of return grossed up for Federal income taxes as proposed in the 2008 ASCM. COUs do not use rate base in determining their retail rates, nor do they pay Federal income taxes. For COUs, we used their weighted cost of debt times their net rate base in service to develop a return component.

Q. *What was the source of data you used to determine the rate of return for the IOUs?*

A. We used the most recently authorized rate of return (ROR) by the IOU's state commission. Idaho Power Company and Avista are multi-jurisdictional, but we chose to use the ROR authorized by the Idaho and Washington jurisdictions respectively because that is where most of their service territories are located. We believe that these rates of return are reflective of the total weighted average ROR. For PacifiCorp, we calculated a weighted average regional ROR by weighting PacifiCorp's Idaho, Oregon, and Washington RORs by the respective rate base allocated to each state.

Q. *What was the source of data you used to determine the rate of return for exchanging COUs?*

A. For exchanging COUs, we used the interest and debt amounts reported in their 2006 annual reports. The weighted cost of debt for Benton County PUD and Snohomish county PUD was based on cost of debt (interest) divided by total debt. Grays Harbor County PUD increased its debt significantly during the 2006 period. Using interest paid during the year divided by end of year total debt would grossly under state its cost of debt in the future. We therefore used interest rates reported on each of its debt instruments times the associated outstanding debt to estimate annual interest expense and then divided annual interest expense by total outstanding debt to estimate Grays Harbor County PUDs weighted cost of debt.

Q. *How did you treat Federal income taxes?*

A. The 2008 ASCM proposes to allow imputed Federal income taxes to be included as an exchangeable cost. We calculated a Federal income tax gross up factor for each IOU based on a 35 percent marginal tax rate. Federal income taxes included in ASC are determined by multiplying the rate base for each IOU by Federal income tax gross up factor for each IOU. To eliminate the potential for double counting, all Federal income tax-related accounts in the FERC Form 1 are functionalized to distribution. *See* Supplemental WPRDS Documentation, WP-07-E-BPA-49B.

Q. How did you reflect purchased power and wholesale revenues in utility ASC determinations?

A. All purchased power and wholesale market revenues were functionalized to production and included in ASC.

Q. Given that BPA proposes to include all transmission costs in ASCs, how did you treat transmission wheeling costs and revenues?

A. We included transmission wheeling costs as exchangeable costs and wheeling revenues as revenue credits.

Section 7: 2006 Base Year Exchangeable Costs and ASCs

Q. What is a base year?

A. The base year is the most currently available FERC Form 1 data for the IOUs and most currently available annual report for the COUs.

Q. Why are you calculating a base year ASC?

A. The base year is the starting point for forecasting the individual FERC accounts and the basis for the forecast ASCs.

Q. Please describe how the base year ASC is calculated.

A. The financial and operating data collected was entered into the 2008 Cookbook. Once the data was entered, it was functionalized into three different categories based on functionalization factors and rules from the proposed 2008 ASCM: (1) Production; (2) Transmission; and (3) Distribution. For a limited number of accounts, BPA used a direct analysis method to review and functionalize costs. The 2008 Cookbook has four basic cost components that were used to calculate each utility's 2006 base year ASC: (1) rate base, which includes return on rate base; (2) operating costs; (3) taxes; and (4) wholesale market revenues and other credits. These costs components are combined in the 2008 Cookbook to produce the base year ASC.

Q. *What are the forecast 2006 base year contract system costs and ASCs for regional utilities using BPA's proposed 2008 ASCM?*

A. The detailed development of the 2006 base year contract system costs and ASCs for the six IOUs and three COUs is described in the Supplemental WPRDS, WP-07-E-BPA-49, Section 8, and Supplemental WPRDS Documentation, WP-07-E-BPA-49B. The 2006 base year contract system costs and ASCs are summarized in Table 2.

Table 2

<u>2006 Base Year Contract System Costs and ASCs</u>

	Contract System Costs	ASC
Avista	$424,579,871	46.02
Idaho Power	474,856,411	32.44
PacifiCorp	964,203,889	42.89
Portland General	922,533,803	47.67
Puget Sound Energy	1,247,530,958	56.33
Northwestern	391,487,720	53.12
Benton PUD	56,612,169	34.67
Grays Harbor PUD	42,058,157	40.34
Snohomish PUD	251,652,839	36.98
Total Residential Exchange Cost	$4,775,515,817	

Section 8: Forecast of Exchanging Utility Loads

Q. *Please describe the load forecasts BPA developed for purposes of forecasting ASCs in this proceeding.*

A. BPA developed two different load forecasts, a system load forecast and a residential load forecast. The system load forecast is used to calculate ASCs. The residential load forecast is used for REP exchange loads.

Q. What is system load?

A. System load is a utility's total retail load (TRL), that is, the metered load that is billed to a utility's retail customers. TRL encompasses all of a utility's end-use consumers, including residential, commercial, and industrial loads. We used the reported load in the FERC Form 1 for the base year ASC. PacifiCorp system load was limited to regional load.

Q. How did you calculate the forecast of contracts system load for the study period?

A. Contract System Load (CSL) is a utility's total retail load (TRL) plus distribution losses. TRL is the total metered load a utility bills its retail customers. The proposed 2008 ASC Methodology requires that distribution losses be included in CSL. We added a loss factor of five percent to each utility's reported TRL to arrive at CSL for the forecast. CSL is the denominator in the ASC calculation. We used BPA's load projections to forecast the total retail load growth over the study period.

Q. Were transmission losses added to system loads?

A. No. Because transmission costs are included in ASCs, it is inappropriate to add transmission losses. By including transmission costs in ASCs, system load is appropriately measured at the transmission-distribution interface.

Q. What were the results of the system load forecasts?

A. The results of the system load forecasts are shown in the ASC Forecast Model and summarized in Table 3. *See* Supplemental WPRDS, WP-07-E-BPA-49, Section 8, and Supplemental WPRDS Documentation, WP-07-E-BPA-49B.

Table 3
Contract System Load Forecast

	2006	2007	2008	2009	2010	2011	2012	2013
Avista	9,226,352	9,392,012	9,572,110	9,778,713	9,983,787	10,184,336	10,359,901	10,472,329
Idaho Power	14,636,280	15,010,497	15,347,626	15,685,835	16,027,291	16,395,492	16,698,932	16,842,446
PacifiCorp	22,480,119	22,424,981	22,701,406	22,882,810	23,133,321	23,401,107	23,772,553	24,144,000
Portland General	19,354,153	19,924,284	20,143,475	20,364,912	20,587,000	20,801,843	21,130,420	21,325,147
Puget Sound	22,146,110	22,283,230	22,563,050	22,872,229	23,171,031	23,456,586	23,669,239	23,875,762
NorthWestern	7,369,983	7,432,023	7,517,227	7,548,152	7,616,681	7,680,502	7,768,772	7,808,903
Benton PUD	1,632,750	1,653,160	1,673,824	1,694,747	1,715,932	1,737,381	1,759,098	1,781,087
Gays Harbor PUD	1,042,473	1,055,504	1,068,697	1,082,056	1,095,582	1,109,277	1,123,143	1,137,182
Snohomish PUD	6,804,274	6,889,328	6,975,445	7,062,639	7,150,923	7,240,310	7,330,815	7,422,451

Q. What is residential load?

A. Residential load is the metered residential and small farm load for each utility. Residential load, as defined in the Northwest Power Act, includes the first four hundred horsepower of farm electrical loads. It differs from the system load forecast because it excludes commercial, industrial, large farm, and other loads.

Q. Are the residential load forecasts used in calculating ASC?

A. Only to the extent they are included in system loads. The residential load forecasts are used in other studies to estimate the total cost of the REP for the study period and the section 7(b)(2) test period. They are not independently used in the calculation of ASC.

Q. How did you forecast residential loads for the study period?

A. We used actual loads reported by the IOUs in their FERC Form 1 and COUs in their annual report. Additionally, we reviewed individual IOU annual reports. When adequate detail was available, irrigation loads were included with actual residential loads. A residential factor was calculated by dividing the actual residential load by the total system load. The forecast total system loads were then multiplied by the residential factor to determine forecast residential loads. The residential factor was assumed to not change over the study period.

Q. What were the results of the residential and small farm load forecasts?

A. The results of the residential and small farm load forecasts are shown in the ASC section of the WPRDS and summarized in Table 4. *See* Supplemental WPRDS, WP-07-E-BPA-49, Section 8, and Supplemental WPRDS Documentation, WP-07-E-BPA-49B.

Table 4
Residential Load Forecasts

	2006	2007	2008	2009	2010	2011	2012	2013
Avista	3,756,579	3,824,029	3,897,357	3,981,477	4,064,974	4,146,629	4,218,112	4,263,887
Idaho Power	7,038,389	7,218,346	7,380,466	7,543,106	7,707,308	7,884,371	8,030,291	8,099,305
PacifiCorp	9,251,568	9,286,925	9,372,307	9,452,784	9,537,185	9,619,100	9,798,021	9,922,831
Portland General	8,049,271	8,286,384	8,377,545	8,469,639	8,562,004	8,651,356	8,788,009	8,868,995
Puget Sound	11,674,554	11,746,838	11,894,349	12,057,336	12,214,852	12,365,385	12,477,488	12,586,358
NorthWestern	898,218	951,068	961,972	965,929	974,699	982,866	994,162	999,297
Benton PUD	3,471,796	3,515,193	3,559,134	3,603,623	3,648,669	3,694,278	3,740,456	3,787,212
Grays Harbor PUD	663,824	672,122	680,523	689,030	697,643	706,363	715,193	724,133
Snohomish PUD	511,237	517,627	524,097	530,649	537,282	543,998	550,798	557,683

Section 9: Escalation Rate and Price Forecasts

Q. Please outline the ASC forecast process.

A. Each line item from the 2008 Cookbook is linked to an escalator in the ASC Forecast Model to escalate the base year values for the years 2007 through 2013. These items include sales for resale revenues, purchased power costs, plant investment, fuel and non-fuel costs. The model is set up to apply different escalation factors to different cost categories.

Q. What was the source for escalators used in the ASC Forecast Model?

A. The ASC Forecast Model uses inflation as escalators. The inflation forecast can be found in the Supplemental Market Price Forecast Study, WP-07-E-BPA-47, and is shown in Table 5 below.

Q. How were inflation rates used to develop the ASC forecasts?

A. Inflation rate forecasts were used to escalate non-fuel costs annually. For an explanation of the calculation and escalation of non-fuel costs, *see* Supplemental Market Price Forecast Study WP-07-E-BPA-47.

Q. Is this the escalation methodology proposed in the 2008 ASCM?

A. No. The escalation procedures for the 2008 ASCM have not been fully developed at this time. The procedures are expected to be completed during the 2008 ASCM consultation. Inflation is used for the forecast until the escalation procedures are completed.

Q. How are fuel costs escalated?

A. The ASC Forecast Model uses BPA's natural gas price forecast to escalate fuel costs for gas-fired resources. The gas price forecasts are the same forecasts used in BPA's WP-07 initial proposal. *See* Supplemental Market Price Forecast Study, WP-07-E-BPA-47, and Table 5 below. Coal costs were escalated by inflation.

Q. How were market price forecasts for electricity used to develop ASC forecasts?

A. Market price forecasts for electricity were used to determine the annual cost of short-term purchased power and additional purchased power needed by a utility to serve increased loads over time. Market price forecasts were also used to determine the value of short-term surplus sales. *See* Supplemental Market Price Forecast Study, WP-07-E-BPA-47 and Table 5 below.

Q. What was the source for the electric market price forecasts?

A. We used market price forecasts contained in the Market Price Forecast Study. *See* Supplemental Market Price Forecast Study, WP-07-E-BPA-47.

Table 5
Escalation Rate and Price Forecasts

	2006	2007	2008	2009	2010	2011	2012	2013
Inflation	1.55%	1.91%	2.06%	2.09%	2.30%	2.48%	2.39%	2.35%
Electricity	58.46	50.87	50.68	51.95	53.25	54.58	55.94	58.46
Natural Gas	6.5554	6.3749	6.1814	5.7702	5.5085	5.7651	6.0920	6.5554

Q. Did you treat COUs differently than IOUs with respect to purchased power?

A. Yes. The information contained in COU annual reports did not separate purchased power using the FERC Form 1 categories, so we modified slightly the assumptions for COUs. For purposes of the Supplemental Proposal, we assumed that annual purchased power cost, as reported in the 2006 annual report for each COU would escalate at the rate of inflation. When COUs file for an ASC, we will have sufficient detail to apply the same procedures used for IOUs.

Q. How did you forecast short-term purchased power costs for the IOUs?

A. For each IOU, the quantity of power purchased in the market varies based on streamflows, weather and performance of thermal generation. State commissions adjust for this by normalizing power purchases to a level that would occur under "normal" conditions. Normalization removes a significant source of variability of costs included in retail rates. In the forecast of individual ASCs, we normalized the quantity of short-term purchases for the 2006 base year by averaging short-term purchases for the years 2002 through 2006 for four of the IOUs. We noticed that PacifiCorp's historical short-term purchases for the 2002 and 2003 period differed substantially from the 2004-2006 period purchases. Therefore, we averaged the short-term purchases over the 2004-2006 period for PacifiCorp. For NorthWestern Energy, we observed that its quantity of short-term purchases for the period prior to 2006 was so significantly different than 2006, we chose to use the 2006 short-term purchases only. The ASC forecast then holds the normalized quantity of short-term purchases constant over the forecast period and prices the power at the forecast market price of PNW electricity.

Q. How does the forecast system load affect forecast ASC?

A. We assumed that each utility was in load-resource balance for the base year and that any increase in system load would be met by resource additions, if any have been identified, or purchased power. *See* Supplemental WPRDS, WP-07-E-BPA-49, Section 8, and Supplemental WPRDS Documentation, WP-07-E-BPA-49B.

Q. Did you make any adjustments to the forecasts to reflect changes in the utility resource portfolio such as new resources, purchased power contracts and terminated resources?

A. No. We did not have information on new, or changes to existing resources and purchased power contracts during the study period. Therefore, we did not forecast any adjustments to any of the utilities' existing resource portfolio. However, the 2008 ASCM proposes to allow utilities to include any known planned resource additions in their ASC filing. As the ASCM process receives and reviews ASC filings for FY 2009, this information will be included in the final determination of ASCs.

Q. How did you forecast the cost of meeting new load growth?

A. If the utility has not identified a new resource addition, we assumed that all future system load growth would be served by market purchases. Thus, the forecast cost of meeting load growth is determined by multiplying the annual system load growth of each utility by the forecast market price of PNW electricity.

Q. Did you make any adjustments to reflect New Large Single Loads (NLSL)?

A. No. At the time this forecast was developed we did not have any detailed information on any NLSL that the exchanging utilities might have. The 2008 ASCM proposes that utilities provide a direct analysis to determine whether any exchanging utilities have NLSL costs that will be removed from the ASC determination.

Q. What are the forecast contract system costs for the utilities?

A. The Table 6 summarizes the forecast contract system costs for 2006-2013.

Table 6
Forecast Contract System Costs

	2006	2007	2008	2009	2010	2011	2012	2013
Avista	424.6	462.0	478.9	495.3	510.2	528.3	552.3	574.2
Idaho Power	474.9	549.7	572.2	599.8	631.0	666.0	699.0	724.0
PacifiCorp	964.2	1,003.5	1,049.4	1,080.0	1,114.0	1,153.4	1,203.1	1,254.5
Portland General	922.5	1,009.7	994.1	1,016.9	1,047.8	1,082.1	1,128.0	1,168.3
Puget Sound	1,247.5	1,209.6	1,204.2	1,236.6	1,277.4	1,321.8	1,366.6	1,412.5
NorthWestern	391.5	385.2	397.4	407.4	420.7	434.8	450.4	463.7
Benton PUD	56.6	58.9	61.0	63.3	65.8	68.6	71.5	74.5
Grays Harbor PUD	42.1	43.7	45.2	46.8	48.6	50.6	52.6	54.7
Snohomish PUD	251.7	261.6	270.7	280.6	291.6	303.7	316.2	329.2

Section 10: Forecast Average System Costs

Q. What are the forecast ASCs?

A. The forecast ASCs are provided in Table 7.

Table 7
Forecast Average System Costs

	2006	2007	2008	2009	2010	2011	2012	2013
Avista	46.02	49.19	50.04	50.65	51.10	51.87	53.31	54.83
Idaho Power	32.44	36.62	37.28	38.24	39.37	40.62	41.86	42.99
PacifiCorp	42.89	44.75	46.23	47.20	48.15	49.29	50.61	51.96
Portland General	47.67	50.68	49.35	49.93	50.90	52.02	53.38	54.79
Puget Sound	56.33	54.28	53.37	54.07	55.13	56.35	57.74	59.16
NorthWestern	53.12	51.83	52.87	53.98	55.23	56.62	57.98	59.38
Benton PUD	34.67	35.64	36.45	37.35	38.37	39.50	40.66	41.84
Grays Harbor PUD	40.34	41.36	42.25	43.23	44.37	45.61	46.85	48.10
Snohomish PUD	36.98	37.97	38.80	39.73	40.78	41.95	43.14	44.35

Section 11: Changes to Average System Cost Forecast

Q. What types of updates will there be for the ASC forecast?

A. BPA will update its ASC forecast with results from the ASCM expedited process as identified in the proposed 2008 ASCM. This public process will take place outside the rate case and the final results will be incorporated into the final Supplemental Proposal.

Q. Are there any known adjustments that BPA plans to make to the ASC forecasts in the final rate proposal?

A. Yes. BPA inadvertently included the Oregon Public Purpose Charge (OPPC) in the calculation of cash working capital. For the purpose of calculating cash working capital, OPPC is not considered an operating expense and should not be a component of cash working capital. For the final proposal BPA will remove the OPPC costs from the calculation of cash working capital. This adjustment should have a minimal impact on a utility's ASC. For example, the effect of including approximately $40 million of PGEs 2006 OPPC in cash working capital results in an increase of contract system cost by only $419,000 out of a total $922 million or less than 5 hundredths (0.045%) of a percent. {*i.e.*, change in contract system costs = (OPPC costs × 1/8) * (ROR + Federal tax factor) = ($40 × 1/8) × (8.4 %+ 2.41%) = $419 thousand}

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY of

SPENCER G. WEDLUND, JON A. HIRSCH, JANET ROSS KLIPPSTEIN,

and ARNOLD L. WAGNER

Witnesses for Bonneville Power Administration

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TESTIMONY of

SPENCER G. WEDLUND, JON A. HIRSCH, JANET ROSS KLIPPSTEIN,

and ARNOLD L. WAGNER

Witnesses for Bonneville Power Administration

SUBJECT: SUPPLEMENTAL REVENUE FORECAST AND PURCHASED POWER EXPENSES

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Spencer G. Wedlund and my qualifications are contained in WP-07-Q-BPA-51.

A. My name is Jon A. Hirsch and my qualifications are contained in WP-07-Q-BPA-16.

A. My name is Janet Ross Klippstein and my qualifications are contained in WP-07-Q-BPA-25.

A. My name is Arnold L. Wagner and my qualifications are contained in WP-07-Q-BPA-50.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to describe the process used to prepare BPA's revenue forecast and to sponsor BPA's revenue forecast contained in Section 5 of the Supplemental Wholesale Power Rate Development Study (WPRDS), WP-07-E-BPA-49, and to sponsor Section 3 of the Supplemental WPRDS Documentation (Documentation), WP-07-E-BPA-49A.

Q. How is your testimony organized?

A. Our testimony contains ten sections, including this introductory section. The second section summarizes BPA's revenue forecast. The third section describes changes to the revenue forecast since the WP-07 Final Proposal. The fourth section describes BPA's forecast of revenues from Subscription products. The fifth section describes BPA's forecast of revenues from long-term contracts. The sixth section describes BPA's forecast of revenue from short-term surplus sales. The seventh section describes BPA's sales of ancillary and reserve services. The eighth section describes BPA's forecast of Treasury credits. The ninth section describes BPA's other revenues. And the tenth section describes BPA's forecast of balancing power purchases and the associated purchased power expense.

Section 2: Revenue Forecast Purpose

Q. What is the purpose of the revenue forecast?

A. The revenue forecast documents the revenue BPA expects to receive during the rate period, given a specified set of rates. Two revenue forecasts were prepared for this proposal; one for revenue from current rates and the other for revenue from proposed rates.

Q. What is the purpose of the current rate revenue forecast?

A. The current rate revenue forecast documents the revenue BPA expects during fiscal years (FY) 2008 and FY 2009, using the rates that were effective October 1, 2006. Pursuant to U.S. Department of Energy Order RA 6120.2, the current revenue forecast is used to test whether the revenue from existing rates satisfies BPA's revenue requirement. *See* Homenick and Lennox, WP-07-E-BPA-65.

Q. What is the purpose of the proposed rate revenue forecast?

A. The proposed rate revenue forecast documents the revenue BPA expects from sales for the rate period (FY 2009) from the proposed rates. This forecast is used to demonstrate that the revenue from proposed rates enables BPA to meet its revenue requirement. *Id.*

Q. What revenues are projected for FY 2008-2009 using current rates?

A. Revenues expected over the next two years, assuming current rates, are: $2,701 million in FY 2008; and $4,985 million in FY 2009. *See* Supplemental WPRDS Documentation, WP-07-E-BPA-49A, Table 3.6.1, line 55.

Q. Why is there such a large difference between FY 2008 and FY 2009 revenues?

A. Because in FY 2009 there is a significant residential exchange load resulting in a large increase in revenue, that is recognized as a net settlement expense in FY 2008. There is now a correspondingly large increase in gross residential exchange program expenses offsetting this increase in revenue. *See* Documentation, WP-07-E-BPA-49A, Table 3.6.1, line 64.

Q. How much revenue is projected to be received in FY 2009 using the proposed rates?

A. Revenues (excluding residential exchange revenue) expected in FY 2009 are $2,633 million. *See* Documentation, WP-07-E-BPA-49A, Table 3.6.2, line 55 minus line 33.

Q. Why is a FY 2008 revenue forecast prepared?

A. The revenue forecast for this time period is used for several purposes, but for this Supplemental Proposal in particular, the forecast is used to determine financial reserves for the beginning of the FY 2009 rate period. Other uses include tracking financial performance.

Section 3: Changes Since the WP-07 Final Proposal

Q. Has BPA's revenue forecast methodology changed since the WP-07 Final Proposal?

A. It has changed to include sales and revenue under the IOU residential exchange program and to include revenue from the sale of generation inputs for wind integration – within-hour balancing service. What follows is the same description presented in our prior testimony (Wedlund, *et al.*, WP-07-E-BPA-19), except that the revenues and rates have been changed to conform to revised forecast for the FY 2008-2009 period.

Section 4: Revenue from Subscription Contracts

Q. What are regional Subscription contracts?

A. "Regional Subscription contracts" refers to those contracts that were signed with BPA's regional customers in the year 2000 for service at the PF, RL, and IP rate schedules.

Q. How is revenue from Subscription contracts estimated?

A. Revenue from Subscription contracts is estimated by multiplying the appropriate power rates by the projected billing determinants – Heavy Load Hour (HLH) energy, Light Load Hour (LLH) energy, demand at time of generation system peak (GSP demand), and total retail load (TRL).

Q. Where are the billing data obtained?

A. The billing data are stored in a database model and the revenues are calculated in that model. The results and the billing data are downloaded to a spreadsheet and included in the revenue forecast. Many customers have requested that BPA keep the data regarding their specific utility or company confidential.

Q. How can parties be certain that BPA's calculations are done properly?

A. BPA's results can be replicated by the parties because the revenue forecast displays the billing quantities, the rates, and the corresponding revenue formulas on those lines where revenue appears. The revenue formulas (which lines to add and multiply) are displayed in the left hand margins. *See* Documentation, WP-07-E-BPA-49A, Tables 3.6.1 and 3.6.2.

Q. Do the formula results match the results coming from the Revenue Forecast Application database?

A. Yes.

Section 5: Revenue from Long-term Contracts

Q. What are the regional and extra-regional long-term contracts?

A. Long-term contracts are those contracts for power sales, contract settlements, capacity sales, pre-Subscription contracts, contract buyouts or cashouts with a duration greater than one year from the initial date of contract implementation.

Q. What are the pre-Subscription contract sales?

A. Pre-Subscription contracts are contract sales made under the FPS rate schedule to firm power requirements customers at fixed rates. There is one pre-Subscription contract, one FPS contract and one Irrigation Mitigation (IRMP) contract in the West Hub providing $8.8 million in revenue in FY 2008, and a single pre-Subscription contract and an FPS contract generating $4.4 million in total in FY 2009, and one IRMP contract generating revenue of $4.4 million in total. There are 12 pre-Subscription contracts and 22 IRMP contracts in the East Hub providing $58.8 million in revenue in FY 2008 and 12 pre-Subscription contracts generating revenue of $35.7 million in FY 2009, and 22 IRMP contracts providing revenue of $15.2 million. The long-term contracts in the East and West Hubs include irrigation mitigation sales made under the FPS rate schedule.

Q. What long-term contracts are included in the Bulk Hub totals?

A. The long-term contracts included in the Bulk Hub sales include sales made at the WNP-3 exchange rate, a WNP-3 Settlement Agreement, a storage agreement for a wind project, and two capacity sales agreements.

Q. How did BPA forecast revenue from regional and extra-regional long-term contracts?

A. Forecasting revenue from regional and extra-regional long-term contracts is done on a contract-by-contract basis in the revenue database, and then sorted into the East, West, or Bulk Hub. The contracts and revenues associated with long-term contracts are grouped together because the contracts contain confidential, business sensitive information, and every one of the contracts has slightly different terms, unlike Subscription power sales which are made under standard terms and rates.

Section 6: Revenue from Short-term Surplus Market Sales

Q. What are short-term surplus market sales?

A. Short-term surplus market sales are sales made from any generation that remains after all firm loads are served. Sales as short as one hour to as long as one year are considered short-term surplus market sales. For this rate proposal they are assumed to be monthly sales and take place either during LLH or HLH. The projected HLH and LLH monthly energy sales, prices, and dollars for each water condition and the average used in this forecast can be found in the Documentation, WP-07-E-BPA-49A, Table 3.8.1.

Q. How were the short-term surplus market sales estimated?

A. Estimation of the short-term surplus market sales is explained in Russell, *et al.*, WP-07-E-BPA-67, where the calculation of short-term surplus market sales is described.

Q. What results were estimated using RiskMod?

A. RiskMod is used to estimate short-term surplus market sales and revenues, balancing power purchases and associated expense, and section 4(h)(10)(C) operational credits. Balancing power purchases and section 4(h)(10)(C) operational credits are discussed below.

Section 7: Revenue from Sales of Generation Inputs for Ancillary and Reserve Services

Q. How did BPA forecast revenue from ancillary and reserve services?

A. The expected sales of and revenue from ancillary and related services are explained in Klippstein, *et al*., WP-07-E-BPA-75. Additional revenue from generation inputs for Wind Integration – Within-hour Balancing Service was estimated using the existing regulation embedded cost rate to generate $14.0 million in FY 2009. This subject is being addressed in the wind integration rate case, 73 Fed. Reg. 7270 (February 7, 2008) and the final Supplemental Proposal may use the rate and billing determinants proposed in the wind integration rate case to estimate the revenue at proposed rates.

Section 8: Treasury Credits

Q. What credits does BPA receive from the U.S. Treasury?

A. BPA receives section 4(h)(10)(C) credits to offset a portion of the additional costs BPA incurs due to changed operations for fish and wildlife recovery, and a credit for payments made to the Colville Tribe.

Q. What are the section 4(h)(10)(C) credits?

A. Section 4(h)(10)(C) is a provision of the Northwest Power Act that creates credits to offset a portion of the additional capital and the additional operating expenses BPA incurs due to changed operations that are paid on behalf of the non-power uses of the Federal Columbia River Power System (FCRPS). 16 U.S.C. § 839b(h)(10)(C). These credits are important because additional operating expenses can vary dramatically based on the effects of water conditions on non-power uses of the FCRPS. The calculation of the section 4(h)(10)(C) credits is described in Russell, *et al.*, WP-07-E-BPA-67.

Q What are the amounts of the operational, expense, and capital credits that make up the section 4(h)(10)(C) credit?

A. Operational credits are expected to total $44.6 million, expense credits are expected to total $32 million, and capital credits are expected to total $8 million during FY 2009.

Q. How much is the Colville Tribe credit?

A. The Colville Tribe credit is fixed at $4.6 million per year beginning in FY 2002.

Section 9: Other Revenue

Q. How did BPA forecast other revenue components?

A. Some of the revenue forecast components are based on recent experience. This is true for miscellaneous revenue, downstream benefits, storage, Reserve Energy, and Irrigation Pumping Power revenue. For example, downstream benefits and Irrigation Pumping Power revenue are based on a historical average.

The remaining revenue components are forecast as follows. Energy Efficiency revenue is based on budgeted activity and generally equal to expenses. Green tag revenues are based on the projected output of renewable resources. Other miscellaneous revenue is an average of revenue over the past few years.

Q. What comprises miscellaneous revenue?

A. Miscellaneous revenue is composed of several items, including: reimbursement for GTA low voltage delivery charges and GTA/OATT transfer services, sale of unused transmission capacity, reimbursement for third-party transmission costs, contract administration fees, reimbursable power expenses, credits and waivers, and miscellaneous billing adjustments.

Section 10: Power Purchases and Purchased Power Expenses

Q. What are the types of purchased power and purchased power expenses that are documented in the revenue and purchased power forecast?

A. The first type of purchased power that this forecast documents is augmentation. Specifically, it documents two types of augmentation expenses: deferred and other augmentation expenses required to achieve critical period load-resource balance in FY 2009. Second, this forecast documents the balancing power purchases required to serve firm load obligations. Finally, there are other purchased power expenses from existing long-term contracts, particularly those costs of a settlement that was signed in

FY 2007 that is written off over a subsequent 30-month period starting in September 2007, and some costs associated with Service and Exchange surplus energy purchase commitments. Residential Exchange purchased power costs (if any) are also shown.

Q. Where are purchased power costs documented?

A. The purchased power costs (excluding Residential Exchange power costs) are documented in the Documentation, WP-07-E-BPA-49A, Table 3.6.2, and described in Russell, *et al.*, WP-07-E-BPA-67.

Q. Are any elements of the revenue forecast likely to change prior to the final Supplemental Proposal?

A. Yes. We will also update our forecast of FY 2008 revenue to reflect our most current outlook for revenues based on billing data, runoff, and market conditions as BPA has in past rate proposals. This will have the effect of changing the level of expected reserves at the beginning of FY 2009.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY of

MICHAEL R. NORMANDEAU, BYRNE E. LOVELL, and ARNOLD L. WAGNER

Witnesses for Bonneville Power Administration

SUBJECT: SUPPLEMENTAL RISK MITIGATION

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TESTIMONY of

MICHAEL NORMANDEAU, BYRNE E. LOVELL, and ARNOLD L. WAGNER

Witnesses for Bonneville Power Administration

SUBJECT: SUPPLEMENTAL RISK MITIGATION

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Michael Normandeau and my qualifications are contained in WP-07-Q-BPA-43.

A. My name is Byrne Lovell and my qualifications are contained in WP-07-Q-BPA-32.

A. My name is Arnold Wagner and my qualifications are contained in WP-07-Q-BPA-50.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to sponsor the Supplemental Risk Analysis Study (Study), WP-07-E-BPA-48, and the Supplemental Risk Analysis Study Documentation (Documentation), WP-07-E-BPA-48A. Also we describe the risk mitigation tools used in this rate case and the calculation of the probability of BPA making U.S. Treasury (Treasury) payments on time and in full during the one-year rate period for this rate proceeding. This testimony also examines additional Risk Mitigation Tools and efforts to reduce the cost of risk mitigation in rates.

Q. How is your testimony organized?

A. Our testimony includes 11 sections including this introductory section. Section 2 summarizes the methodology for calculating the probability of making all Treasury payments in full and on time. Section 3 surveys the risk mitigation tools used in the ToolKit model. Section 4 discusses financial reserves. Section 5 goes over Planned Net Revenues for Risk (PNRR). Section 6 is devoted to the Cost Recovery Adjustment Clause (CRAC). Section 7 describes the NFB Adjustment to the CRAC. Section 8 explains the Dividend Distribution Clause (DDC). Section 9 details the calculation of Modified Net Revenue (MNR). Section 10 highlights other possible risk mitigation measures that are not quantitatively assessed in this proposal. Section 11 discusses the timing of the provisions of the proposed rates for fiscal year (FY) 2009 with those of the rates currently in effect for FY 2009.

Section 2: Treasury Payment Probability Methodology

Q. What is the Treasury Payment Probability)?

A. Treasury Payment Probability (TPP) is the probability (expressed as a percentage) that BPA will be able to make all of its planned payments to Treasury in a rate period in full and on time. TPP is the means by which BPA tests the financial strength of its rate proposal. Payments to Treasury, in particular principal payments, are by law subordinate to all of BPA's other payment obligations. Therefore, if BPA meets its Treasury payment obligations, it will have met all its other financial obligations as well. For this reason, TPP serves as the key prospective measure of BPA's ability to recover all its costs.

Q. How do you calculate the TPP?

A. We calculate TPP using a *Monte Carlo* modeling approach in which 3,000 separate scenarios or *games* are generated. Each game covers two years – the year prior to the rate period, FY 2008, and the single year of the rate period, FY 2009. In each game a test is performed to see if BPA is able to make its Treasury payment during FY 2009. FY 2008 is simulated in order to reflect the effect of uncertainty during FY 2008 on the starting 2009 balance of reserves available for risk. The TPP is the percentage of those 3,000 games in which BPA makes its Treasury payment on time and in full in FY 2009.

Q. What tool do you use to calculate the TPP?

A. We use a model called the ToolKit to evaluate Power Services' ability to meet the TPP standard, given the net revenue variability embodied in the distributions of operating and non-operating risks. ToolKit is used to assess the effects of various policies, assumptions, changes in data, and risk mitigation measures on the level of year-end reserves attributable to generation.

Q. How have you modified the ToolKit Model since the WP-07 Final Proposal?

A. The version of ToolKit used in the WP-07 Supplemental Proposal is very similar to the version used in the WP-07 Final Proposal. The ToolKit reads in two files of risk data, one produced by the RiskMod model that reflects operating risks, and one from the Non-Operating Risk Model (NORM). However, we have modified the Visual Basic for Applications (VBA) code of ToolKit to account for two changes: the IOU REP Settlement is no longer in effect; and the rate period is now a single year (FY 2009) instead of three years (FY 2007-2009.) *See* Russell, *et al.*, WP-07-E-BPA-67 for an updated discussion of the RiskMod and the NORM and for more details on changes to the ToolKit.

Q. What TPP percentage is BPA targeting with its WP-07 Supplemental Proposal?

A. In this Supplemental Proposal, BPA is implementing its long-standing TPP standard of 95 percent. That standard, adopted in 1993 as part of BPA's 10-Year Financial Plan, applies to a two-year rate period. Because the FY 2009 rate period is a one-year period, we must convert the 95 percent TPP for two-year rate periods into the equivalent TPP percentage for a one-year rate period. The one-year equivalent TPP is 97.5 percent.

Q. How do you measure TPP for comparison to its TPP standard?

A. We measure TPP in the ratesetting process used by each business function. The TPP standard is a ratesetting standard, and because BPA now sets rates separately for the power and transmission functions, the TPP test must be made separately also. BPA believes that if each business function is meeting the TPP standard, then the Agency as a whole is ensuring timely payment of its Treasury obligations sufficiently to comply with the thrust of the TPP standard. Therefore, the proposed power rates must meet the one-year standard of 97.5 percent.

Section 3: Risk Mitigation Tools in the ToolKit Model

Q. What risk mitigation tools is BPA using to achieve the 97.5 percent TPP standard?

A. BPA identified a list of potential risk management tools to be used as part of a comprehensive risk management plan in Supplemental Risk Analysis Study, WP-07-E-BPA-48. The tools that are included in the ToolKit analysis for the Supplemental Proposal are liquidity reserve level, starting Power financial reserves available for risk, temporary availability of Transmission financial reserves, a Cost Recovery Adjustment Clause (CRAC), a Dividend Distribution Clause (DDC), and Planned Net Revenues for Risk (PNRR). These tools address the uncertainties BPA is facing for FY 2008 and 2009, particularly hydro conditions, market prices, operating and non-operating costs, and fish and wildlife costs while assuring that reserves available for risk that are attributed to Power Services do not accumulate to unnecessarily high levels.

Q. Does the Supplemental Proposal contain other risk mitigation tools that are not modeled in ToolKit?

A. Yes. We are proposing to continue the NFB Adjustment (National Marine Fisheries Service [NMFS] Federal Columbia River Power System [FCRPS] Biological Opinion [BiOp] Adjustment) and the Emergency NFB Surcharge, but are not modeling them or the risks they mitigate. The NFB Adjustment is an upward adjustment to the CRAC Maximum Planned Recovery Amount (Cap) for FY 2009 if unforeseen fish and wildlife costs or financial impacts of operational changes arise from a prescribed set of circumstances in FY 2008 related to the litigation over the FCRPS BiOp. The Emergency NFB Surcharge mitigates the risks of the same set of possible events that might occur during FY 2009 should BPA be experiencing a cash crunch during FY 2009. We are not modeling the impacts of these risk tools or the risks they cover because BPA would prefer not to model in a rate case the potential independent actions of the Federal court or the possible outcomes of on-going negotiations for long-term agreements regarding fish funding levels. *See* Section 7 for further discussion of the NFB Adjustment.

Q. What do you mean by a "cash crunch"?

A. A cash crunch is defined as occurring when the Agency Within-year TPP for the fiscal year in which the NFB Trigger Event has occurred is calculated to be less than 80 percent when the financial effects of the Trigger Event, but not the revenues from the NFB Surcharge, are taken into account.

Q. Will the risk mitigation package apply to Slice purchases?

A. No. The Slice product is not subject to the proposed risk mitigation package because Slice customers cover their proportional share of risk by paying actual costs via a true-up mechanism and they receive their proportional share of actual secondary power.

Section 4: Financial Reserves Available for Risk

Q. Please explain the term "starting financial reserves available for risk."

A. Starting financial reserves available for risk comprise cash in the Bonneville Fund and cash equivalents in the form of a deferred borrowing balance at the start of the first fiscal year of the rate period, *i.e.*, FY 2009. Since BPA is setting rates only for power in this rate case, it is only referring to those financial reserves attributable to the generation function.

Q. What does the phrase "available for risk" mean?

A. Some of the reserves attributed to Power Services at the beginning of FY 2008 are not considered to be available for risk because they are virtually certain to be distributed to customers in the near future. These are the reserves that BPA has accumulated due to the cessation in May 2007 of residential exchange benefit payments to the IOUs.

During the remainder of FY 2007, BPA's power rates continued to generate revenue to cover the expense of the residential exchange benefit payments even though these payments had been stopped. At the start of FY 2008, this had amounted to a total of $141.3 million. That amount has been subtracted from the reserves attributed to Power Services at the beginning of FY 2008 in BPA's calculation of the starting reserves available for risk.

Q. Please explain how financial reserves are modeled as a risk mitigation tool.

A. Financial reserves are BPA's central risk mitigation tool. During years of low secondary revenue or other financial exigencies, reserves can be drawn upon to provide funds for paying operating expenses and paying the Treasury, and during years of high net revenue reserves they can be replenished. The first step in BPA's calculation of TPP is modeling starting financial reserves available for risk for the rate period.

Q. What are you assuming for FY 2009 starting reserves?

A. At the time of this analysis, the actual starting reserve level for FY 2009 cannot be known because of the uncertainty regarding Power Services' cash flow during the remainder of FY 2008. To account for this uncertainty, we have modeled 3,000 games for FY 2008 to produce 3,000 separate starting reserve values for FY 2009. The result showed an expected value of Power starting reserves available for risk for FY 2009 of $1,031 million.

Q. Does this mean BPA will have Power reserves available for risk of $1,031 million at the start of FY 2009?

A. No. The actual amount of starting reserves for FY 2009 is unknown. We are using the ToolKit model, along with RiskMod and NORM, to compute a distribution of 3,000 different starting reserve values for FY 2009. The expected value of our distribution of starting reserves is $1,031 million; the distribution ranges from a low of $50 million (reflecting a deferral of part of the Treasury payment for FY 2008) up to $2,712 million.

Q. Does the Supplemental Proposal risk mitigation rely solely upon reserves attributed to Power?

A. Yes, the reserves relied upon are only those reserves available for risk that are attributed to Power, and not other agency reserves, with the exception that the definition of cash crunch involves an assessment of the Agency Within-year TPP.

Q. The temporary availability of other reserves for use in PBL rate-setting was one of the tools in the WP-07 Final Proposal. Why are you not including such reserves in the Supplemental Proposal?

A. The WP-07 Final Proposal assumed some reserves attributed to the Transmission function could be temporarily used by PBL in only one of the three years covered by that PBL rate case, FY 2007. This possibility and the amount was calculated in the Transmission Business Line's TR-06 rate case; no similar amount was determined from Transmission Services' rate cases for other years to be temporarily available to the Power function, therefore we have not assumed that any reserves that are not attributed to Power are available, even temporarily, in the Supplemental Proposal.

Section 5: Planned Net Revenues for Risk

Q. What is the role of Planned Net Revenues for Risk?

A. BPA often includes PNRR as a component of the revenue requirement to bolster reserves to mitigate the impacts of operating and non-operating risks. However, in this Supplemental Proposal, we are not proposing to include PNRR. The rate period comprises only a single year, which reduces the total amount of risk to be mitigated, and the projections of starting reserves available for risk are unusually robust. These reserves, combined with a modest CRAC (*see* next section,) are sufficient to meet BPA's TPP standard without reliance on PNRR.

Section 6: Cost Recovery Adjustment Clause (CRAC)

Q. Is the CRAC in the Supplemental Proposal similar to the CRAC in the WP-07 Final Proposal?

A. Yes. It is a temporary upward adjustment to the power rates if forecast Accumulated Modified Net Revenues (AMNR) fall below the threshold shown on Table A, Attachment 1. The adjustment will be made by a percentage increase in light load hour (LLH), heavy load hour (HLH) energy and load variance rates. *See* Supplemental Wholesale Power Rate Development Study (WPRDS), WP-07-E-BPA-49.

Q. Please explain the timing of the CRAC adjustment.

A. Before the end of FY 2008, BPA will determine if the forecast of year-end AMNR is below the CRAC threshold for the CRAC applying to FY 2009. If AMNR is below the threshold, BPA will adjust energy rates for FY 2009. The adjustment will be a percentage increase to the applicable posted rates. This initial proposal does not call for a forecast of AMNR to be made in FY 2009, since the next year, FY 2010, is outside the rate period, and any CRAC that might apply to FY 2010 would be described in the rate case for that subsequent rate period.

Q. How was the CRAC threshold derived?

A. The threshold was originally discussed in terms of reserves because reserves are easier for many people to relate to BPA's financial position. BPA determined in the WP-07 Final Proposal that approximately $750 million was an appropriate threshold level because it represented an appropriate compromise between a lower threshold that would trigger less frequently but require higher PNRR, and a higher threshold with higher total CRAC revenues but a lower level of PNRR. We propose to continue to use $750 million of reserves available for risk as the CRAC threshold in this Supplemental Proposal.

Q. *Why is $36 million the maximum recovery amount instead of $300 million?*

A. Because the projections of reserves available for risk are unusually robust, and this is a one-year rate period instead of a three-year rate period, a $36 million cap is sufficient to meet the 97.5 percent TPP standard without relying on PNRR with the risks of FY 2008 and FY 2009 that we have modeled.

Q. *What would be the effect of changing the maximum recovery amount of the CRAC?*

A. If the cap were increased above $36 million, the TPP would be higher than the targeted standard of 97.5 percent; if the cap were decreased below $36 million, the TPP would be below the targeted TPP standard and PNRR would have to be added to the revenue requirement.

Q. *How is the total amount to be recovered through the CRAC adjustment determined?*

A. The total amount to be recovered through the CRAC adjustment is the lesser of the amount by which AMNR is below the threshold and the maximum recovery amount shown in Attachment 1, Table A.

Q. *How is the amount of rate increase calculated?*

A. The CRAC amount will be recovered from the energy rates subject to the CRAC, which would both increase revenues from adjustable power rate sales and decrease the REP payments to exchanging utilities by increasing the PF Exchange rate.

Q. *Please explain the CRAC Revenue Basis.*

A. The CRAC Revenue Basis is the total LLH and HLH generation revenue for products and benefits that are subject to the CRAC, based on the most current revenue forecast available in September 2008 for FY 2009.

Q. *How will the CRAC percentage be applied to customer bills?*

A. The CRAC percentage will be applied as a mills/kWh rate to the customer's HLH and LLH energy and load variance rates. The CRAC adjustments will be shown as separate line items on each customer's bill. *See* Bolden, *et al*., WP-07-E-13-BPA, for an explanation about the CRAC application to the demand rate.

Q. Will there be a true-up of the CRAC?

A. No. The CRAC adjustment to the rates is made based on the CRAC percentage calculated prior to the start of the fiscal year with no true-up. Any over-collection or under-collection due to changes between the third quarter review and the end of the fiscal year will be addressed in the next fiscal year's analysis of the need for a CRAC.

Q. Is the CRAC robust enough to mitigate all of BPA's risk?

A. It is robust enough to meet BPA's TPP standard without any reliance on PNRR for the FY 2009 rate period; this does not eliminate or totally mitigate risk, because the TPP standard allows a 2.5 percent chance of a Treasury deferral in FY 2009.

Section 7: The NFB Adjustment and the Emergency NFB Surcharge

Q. Are fish and wildlife issues being handled in the TPP modeling in a fashion similar to the approach in the WP-07 Final Proposal?

A. Yes. A base river operation is used in RiskMod, and a base F&W program is reflected in the revenue requirement. Then some uncertainty over some program elements is modeled in NORM (BPA direct program costs, and U.S. F&WS Lower Snake River Hatcheries. *See* Risk Analysis Study, WP-07-E-BPA-48, Section 2.5.3.7.

Q. Are the fish issues that are not modeled being treated the same as in the WP-07 Final Proposal?

A. Yes. The WP-07 Final Proposal included both the NFB Adjustment and the Emergency NFB Surcharge, and this Supplemental Proposal also includes both.

Section 8: Dividend Distribution Clause (DDC)

Q. Is the DDC in this Supplemental Proposal similar to the DDC in the WP-07 Final Proposal?

A. Yes. It is virtually identical, except that the threshold as measured in AMNR is different. The starting point for this threshold is the same level of reserves available for risk, $1,050 million. The threshold measured in AMNR is now $218.6 million.

Section 9: Modified Net Revenue

Q. Have changes been made to the manner in which BPA calculates Modified Net Revenue (MNR) or Accumulated Modified Net Revenue (AMNR)?

A. No, they are calculated in the same way as in the WP-07 Final Proposal.

Section 10: Additional Risk Mitigation Tools and Efforts

Q. Are there other risk mitigation efforts currently underway that are not included in this analysis?

A. No. If significant issues are raised in the parties' testimony regarding risk mitigation, BPA would consider changes to its risk mitigation approach as necessary.

Section 11: The Relationship of the Proposed NFB Rate Provisions to the Current NFB Rate Provisions

Q. What is an NFB Trigger Event?

A. According to language agreed to in meetings with customers and other parties during the WP-07 rate proceeding, an NFB Trigger Event is an event of one of the following four events that results in changes to BPA's FCRPS Endangered Species Act (ESA) obligations compared to those in the WP-07 Final Proposal as modified prior to this Trigger Event:

(1) A court order in *National Wildlife Federation vs. National Marine Fisheries*, CV 01-640-RE, or any appeal thereof ("Litigation");

(2) An agreement (whether or not approved by the Court) that results in the resolution of issues in, or the withdrawal of parties from, the Litigation;

(3) A new NMFS FCRPS BiOp; or

(4) A BPA commitment to implement Recovery Plans under the ESA that results in the resolution of issues in, or the withdrawal of parties from, the Litigation.

Q. How would an NFB Trigger Event affect rates?

A. It depends on when the NFB Trigger Event occurs and whether BPA is in a cash crunch or not (this is what determines whether an NFB Trigger Event might lead to an NFB Adjustment for the following year or an Emergency NFB Surcharge for the current year). If BPA is in a cash crunch when the NFB Trigger Event occurs, then we will follow the GRSPs for possible implementation of an Emergency NFB Surcharge. We are not proposing to change the procedure specified in the GRSPs governing Emergency NFB Surcharges, so we would undertake the same sequence of actions whether an NFB Trigger Event occurs at the time of a cash crunch in FY 2008 or FY 2009.

Q. What would happen if an NFB Trigger Event occurs in FY 2009 and BPA is not in a cash crunch?

A. The proposed rates do not provide for any response to those circumstances because the conditions for applying an Emergency NFB Surcharge to FY 2009 rates would not have been met, and any NFB Adjustment that might ensue would occur in FY 2010, and BPA is not proposing any rates that apply to that year.

Q. OK. What would happen if an NFB Trigger Event occurs in FY 2008 and BPA is not in a cash crunch?

A. To answer that, let's look in more detail at the timing of the calculations for an NFB Adjustment to FY 2009 rates. The current GRSPs call for calculations in August 2008, at essentially the same time as the calculations for determining whether there will be a CRAC or DDC during FY 2009; we are proposing to change this to early September in this Supplemental Proposal. In either case, BPA will be analyzing the financial impacts in the August-September time frame along with the CRAC/DDC calculations. If BPA anticipates that the proposed rates will receive interim approval from the Federal Energy Regulatory Commission by October 1, 2008, BPA will use the proposed GRSPs to analyze the financial impacts of the NFB Trigger Event to determine how much of a change to the CRAC cap to make, and the financial impact will be calculated in reference to the operation and program for FY 2008 that were assumed in the final Supplemental Proposal. On the other hand, if BPA anticipates that the current rates will be in effect on October 1, 2008, BPA will use the current GRSPs to make the NFB and CRAC calculations, and the financial impact will be calculated in reference to the FY 2008 operation and program, as adjusted, that were assumed in the WP-07 Final Proposal.

Q. What does "as adjusted" mean?

A. It means that the fish and wildlife operation or fish and wildlife program (or both) that BPA is implements in a fiscal year (*e.g.*, FY 2008) may not be exactly the same as that assumed in the most recent rate case final proposal (*e.g.*, the WP-07 Final Proposal), because BPA may have modified that operation and program after completing the relevant final proposal – that is, the baseline for the "before" part of the NFB Trigger Event impact calculation may have changed. The possibility of changes to the baseline was foreseen during the design of the NFB mechanisms and the writing of the WP-07 Final Proposal GRSPs. The baseline needs to include the possibility of change because customers feared that BPA could voluntarily make changes to the operation and program that would increase expenses, and then, if an NFB Trigger Event occurred, roll the voluntary changes in with the litigation-related changes and increase rates more than could have been justified by the litigation-related changes alone. So “as adjusted” merely means the operation and program that BPA is implementing as of the time immediately before the NFB Trigger Event occurs.

Q. Does it matter when during FY 2008 an NFB Trigger Event occurs?

A. Yes, it does, if we anticipate that the proposed rates will go into effect on October 1, 2008. Let’s consider first an FY 2008 NFB Trigger Event that occurs after completion of the modeling for the Final Supplemental Proposal. In that case, we will follow the proposed GRSPs, which call for calculating the financial impact of the NFB Trigger Event by comparing estimates of FY 2008 net revenue including the impact of the NFB Trigger Event to estimates of FY 2008 net revenue under the operations and program assumptions of the final Supplemental Proposal, as adjusted.

Q. What about the case where an NFB Trigger Event occurs before the final Supplemental Proposal is completed and you anticipate that the proposed rates will go into effect on October 1, 2008?

A. If an NFB Trigger Event occurs in FY 2008 early enough that that its impacts can be factored into the final Supplemental Proposal, that is, modeling of FY 2008 can be updated to reflect the NFB Trigger Event and if the NFB Trigger Event has effects on FY 2009, modeling of FY 2009 can be updated to reflect the NFB Trigger Event, then the calculations are quite different. The Supplemental Proposal GRSPs propose calculating financial impacts of NFB Trigger Events by comparing FY 2008 net revenue after the NFB Trigger Event to FY 2008 net revenue as modeled in the final Supplemental Proposal. Since in this case, the final Supplemental Proposal has already incorporated the NFB Trigger Event, there would be no impacts of the NFB Trigger Event. The updating of the assumptions about operations and program in the final Supplemental Proposal will have superseded the NFB Adjustment, and there will not be an NFB Adjustment for this NFB Trigger Event.

Q. *Doesn't this mean that the net revenue impacts of this NFB Trigger Event are missed, and are not recovered?*

A. No, they are fully recovered. By incorporating the FY 2008 effects into the modeling of FY 2008, which affects FY 2009 starting reserves, and incorporating the FY 2009 effects into the revenue requirement for the FY 2009 rates, and then ensuring that the FY 2009 rates meet BPA's TPP standard, the financial impacts of the NFB Trigger Event on both FY 2008 and FY 2009 are fully accounted for in the revised FY 2009 rates.

Q. *Will BPA still go through the formal process of calculating an NFB Adjustment to the cap on the CRAC if there isn't likely to be a CRAC?*

A. No. In the August-September calculations, BPA will calculate first whether a CRAC will trigger. If the CRAC will not trigger, then an NFB Adjustment would have no impact, and BPA will not necessarily calculate the financial impacts of an NFB Trigger Event with the rigor that would be needed if it were to affect rates.

Q. *Could an FY 2008 NFB Trigger Event affect rates in both FY 2008 and FY 2009?*

A. Yes, there are two scenarios in which this could happen. First, an NFB Trigger Event in FY 2008 could come when there is a cash crunch, but there isn't enough time remaining in FY 2008 to collect additional revenue equal to the magnitude of the financial impact of the NFB Trigger Event. Then the balance of the financial impact could result in an NFB Adjustment to the FY 2009 CRAC cap.

Second, an NFB Trigger Event could occur that affects operations or program elements in both FY 2008 and FY 2009. This could lead to what was termed a "deemed" Trigger Event in the WP-07 Final Proposal: as soon as FY 2009 begins, an NFB Trigger Event is deemed to have occurred in FY 2009; the event actually occurred in FY 2008, but has effects on FY 2009 financial results. Both the original and the deemed NFB Trigger Event could lead to Emergency NFB Surcharges (for rates in FY 2008 and FY 2009, respectively).

Q. Could two separate NFB Trigger Events affect FY 2009 rates?

A. Yes, there are several ways this could occur. First, there could be two or more NFB Trigger Events in FY 2008 in the absence of a cash crunch. These events would be evaluated in the August-September time frame in a single analysis that might lead to an NFB Adjustment to the FY 2009 CRAC cap.

Second, an NFB Trigger Event could occur in FY 2008 in the absence of a cash crunch and lead to a change in the CRAC cap; if the CRAC triggers, this could increase FY 2009 rates. Then an NFB Trigger Event could occur during FY 2009 when a cash crunch is occurring, leading to implementation of an Emergency NFB Surcharge in FY 2009 in addition to the CRAC that had been increased by the FY 2008 NFB Trigger Event.

Third, there could be two or more NFB Trigger Events in FY 2009 that each lead to Emergency NFB Adjustments. One of these events could be a deemed NFB Trigger Event that is assessed as soon as FY 2009 begins. Since the existence of a cash crunch implies that urgent measures are needed, Emergency NFB Surcharges are supposed to be implemented rapidly, so the first Emergency NFB Surcharge might already have been put in place when the second NFB Trigger Event occurs.

Q. Do you anticipate NFB Trigger Events in FY 2008?

A. Yes, we believe one NFB Trigger Event is highly likely (issuance of the final FCRPS BiOp is scheduled for May 5, 2008) and another is more likely than not (execution of one or more agreements that results in the resolution of issues in, or the withdrawal of parties from, the Litigation). We also anticipate that there could be a court order regarding the Litigation in FY 2008; however, the timing of the order, and whether or not it would result in changes to BPA's FCRPS obligations compared to those in the final Supplemental Proposal remain uncertain.

Q. Are there other Biological Opinions being litigated that could affect BPA's fish and wildlife costs?

A. Yes, there is on-going litigation regarding the issuance of a BiOp for the Willamette Valley Projects of the FCRPS, and on-going litigation regarding a BiOp for the Libby Project.

Q. Would either of these cases or BiOps be covered under the NFB clauses?

A. No, by their terms, NFB clauses are limited to events relating to the litigation over ESA obligations in the *National Wildlife Federal v National Marine Fisheries Service* case only.

Q. Have you considered modifying the NFB Adjustment clause and the Emergency NFB Surcharge to cover litigation over these other BiOps?

A. Yes, we considered this, but determined it was not needed for this FY 2009 rate period. We believe it is highly unlikely that financial impacts from either BiOp could decrease BPA's net revenue very substantially during FY 2009. We could, however, consider modifying or expanding the NFB clauses in future rate cases if determined necessary or appropriate.

Q. Does this conclude your testimony?

A. Yes.

Attachment 1

Table A: CRAC Annual Thresholds and Caps

[Dollars in millions]

AMNR Calculated at end of Fiscal Year	CRAC Applied to Fiscal Year	CRAC Threshold	Approx. Threshold as Measured in PS Reserves	Maximum CRAC Recovery Amount (Cap)
2008	2009	-$81.4	$750	$36

Table B: DDC Thresholds

[Dollars in millions]

AMNR Calculated at End of Fiscal Year	DDC Applied to Fiscal Year	DDC Threshold in AMNR	Approx. Threshold as Measured in PS Reserves
2008	2009	$218.6	$1,050

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TESTIMONY of

CARIE LEE, RONALD HOMENICK, JANICE A. JOHNSON, and BYRON KEEP

Witnesses for Bonneville Power Administration

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TESTIMONY of

CARIE E. LEE, RONALD J. HOMENICK, JANICE A. JOHNSON, and BYRON G. KEEP

Witnesses for Bonneville Power Administration

SUBJECT: SUPPLEMENTAL SLICE REVENUE REQUIREMENT AND RATE

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Carie E. Lee and my qualifications are contained in WP-07-Q-BPA-28.

A. My name is Ronald J. Homenick and my qualifications are contained in WP-07-Q-BPA-17.

A. My name is Janice A. Johnson and my qualifications are contained in WP-07-Q-BPA-63.

A. My name is Byron G. Keep and my qualifications are contained in WP-07-Q-BPA-22.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to: (1) explain changes to the Slice Revenue Requirement for FY 2009; (2) describe how any reductions in expenses related to the IOU Residential Exchange Program benefits will affect the Slice rate or Slice True-Up; and, (3) sponsor portions of the 2007 Supplemental Wholesale Power Rate Development Study (WPRDS) and the 2007 Supplemental Wholesale Power Rate Schedules and General Rate Schedule Provisions (GRSPs) related to the Slice rate development and the Slice True-Up.

Q. How is your testimony organized?

A. This testimony contains seven sections, including this introductory section. In Section 2, the testimony describes the proposed changes to the Slice Revenue Requirement and Slice Rate. Section 3 describes the proposed Slice True-Up and Related Changes Due to the Slice Mediation Settlement Agreement (Slice Settlement).

Section 4 describes Expenses Related to the 2000 Residential Exchange Program Settlement Agreements (REP Settlement Agreements). Section 5 describes the proposed updates to the Methodology to Calculate Slice Rate and Slice True-Up Adjustment Charge. Table 1, Slice Product Costing and True-Up Table, follows these sections.

Q. Have you sponsored other testimonies or studies related to the Slice Revenue Requirement and Slice rate in the past?

A. Yes. *See* Lee, *et al.*, WP-07-E-BPA-23; Lee, *et al.*, WP-07-E-BPA-35; and WPRDS, WP-07-FS-BPA-05, Section 2.14.

Section 2: Slice Revenue Requirement and Slice Rate

Q. What is the Slice Revenue Requirement?

A. The Slice Revenue Requirement is the list of expenses and revenue credits used to calculate the Slice rate. The Slice Revenue Requirement includes the same expenses and revenue credits that are included in BPA's generation revenue requirement with certain limited exclusions. Table 1 following this testimony contains the Slice Revenue Requirement proposed for this WP-07 Supplemental Proposal for the FY 2007-2009 rate period that is the basis for the proposed FY 2009 Slice rate.

Q. Is BPA revising the Slice Revenue Requirement for FY 2009?

A. Yes.

Q. Why is BPA revising the Slice Revenue Requirement for FY 2009?

A. BPA is revising the Slice Revenue Requirement for FY 2009 to reflect the updates to the generation revenue requirement. *See* Homenick and Lennox, WP-07-E-BPA-65. For the Slice Revenue Requirement for FY 2009, BPA eliminated the expenses related to the REP Settlement Agreements, 2001 Load Reduction Agreements, and 2004 Settlement Amendments (collectively, REP settlements) in light of the invalidation of these Agreements by the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit). *See*

Bliven, *et al.*, WP-07-E-BPA-52. The Slice Revenue Requirement also includes the net expense for the REP calculated in this rate proceeding. *See* Section 4 below for more details on the REP expenses.

Q. What is the Slice rate?

A. The Slice rate is the monthly dollar amount that is charged to Slice customers per one percent of Slice product purchased. The Slice Revenue Requirement is the basis for calculating the Slice rate.

Q. Are you proposing changes to the method used to calculate the Slice rate?

A. No.

Q. Please explain how the Slice rate is calculated.

A. To calculate the Slice rate, the total dollar amounts for each fiscal year of the Slice Revenue Requirement are summed and divided by 36 months (the number of months in the three-year rate period FY 2007-2009) and divided by 100 to obtain the monthly base Slice rate per one percent of Slice product purchased.

Q. How much is the monthly Slice rate per percent of Slice product purchased?

A. For the Supplemental Proposal, the proposed monthly Slice rate is $1,840,005 per one percent Slice product purchased for FY 2009. BPA is proposing no adjustments to the Slice Revenue Requirement for FY 2007 or FY 2008. Instead, any adjustments necessary to reflect the difference between forecast expenses for the REP settlements included in the Slice Revenue Requirement for FY 2007 and FY 2008 and those calculated in this proceeding for REP benefits for FY 2007 and FY 2008 will be handled through the Slice True-Up for FY 2008 or through other mechanisms developed in this proceeding. *See* Marks, *et al.,* WP-07-E-BPA-62.

Section 3: Slice True-Up and Related Changes Due to the Slice Mediation Settlement Agreement

Q. What is the Slice True-Up?

A. The Slice True-Up is a process that ensures that Slice customers pay their share of Power Service's actual expenses and receive their share of actual revenue credits applicable to Slice Revenue Requirement.

Q. Has BPA changed the True-Up process since the WP-07 Final Proposal?

A. Yes.

Q. Why did BPA change the True-Up process?

A. BPA changed the True-Up process as a result of the Slice Settlement (07PB-12273) BPA signed with Slice customers and Northwest Requirements Utilities on November 22, 2006. The Slice Settlement provided, in part, for a change in the way that the Slice True-Up would be calculated, beginning in FY 2007. At the time that the WP-07 Final Proposal was published, BPA was engaged in litigation before the Ninth Circuit concerning the appropriate interpretation and implementation of the Slice rate and Slice Rate Methodology. *Northwest Requirements Utilities v. Bonneville Power Administration,* Nos. 03-73849, 03-74170, and 04-71311. BPA acknowledged in the WP-07 Final Proposal that a settlement could be reached in the litigation which would obviate the need for some or all of the clarifications proposed in the WP-07 Final Proposal. *See* WPRDS, WP-07-FS-BPA-05, at 37. As a consequence of the Slice Settlement, BPA is proposing in this proceeding to formally adopt the aspects of the Slice Settlement that impact the Slice True-Up.

Q. How has the Slice Settlement changed the True-Up process from the WP-07 Final Proposal?

A. Prior to the Slice Settlement, BPA calculated the difference between the Actual Slice Revenue Requirement for the applicable fiscal year and the Slice Revenue Requirement for the applicable fiscal year. *See* WPRDS, WP-07-FS-BPA-05, at 50. Pursuant to the

Slice Settlement Agreement, BPA agreed to calculate the Slice True-Up based upon the difference between the Actual Slice Revenue Requirement for the applicable fiscal year and the **average** Slice Revenue Requirement for the applicable period upon which the Slice rate is based. In order to do this, BPA summed the Slice Revenue Requirement for each of the three years of the rate period and divided by three. This produced the average Slice Revenue Requirement against which the Actual Slice Revenue Requirement is compared.

Q. How will the True-Up process work in light of the fact that the Slice Revenue Requirement for FY 2009 is changing?

A. In light of the fact that the Slice Revenue Requirement for FY 2009 will change, BPA will revise the **average** Slice Revenue Requirement used in the Slice True-Up for FY 2009. *See* Table 1, Slice Product Costing and True-Up Table, line 158, for the calculation of the average Slice Revenue Requirement resulting from this proceeding.

To calculate the Slice True-Up for FY 2009, BPA will subtract the average Slice Revenue Requirement for FY 2007-2009 that results from this proceeding from the Actual Slice Revenue Requirement for FY 2009. The difference between the Actual Slice Revenue Requirement and the average Slice Revenue Requirement will determine the Slice True-Up Amount. A positive or negative result from the calculation will result in an additional charge or credit to the Slice customers.

Q. Are there other changes due to the Slice Settlement?

A. Yes. The treatment of certain bad debt expenses in the Slice True-Up changed. The treatment of bad debt expense related to the California Independent System Operator and California Power Exchange (CAISO/PX) and any related recoveries has changed.

Q. *How did the treatment of CAISO/PX bad debt expense and any related recoveries change?*

A. As per the Slice Settlement, BPA reversed the True-Up Adjustment Charges to Slice customers for the bad debt expense arising out of transactions with the CAISO/PX prior to October 1, 2001. As a result, Slice customers will not receive any future credits for recovery of any receivables related to amounts previously written off that BPA collects, nor will the Slice customers pay for any future bad debt expense related to write-offs of any outstanding CAISO/PX receivables.

Q. *Did other treatments of bad debt expense change as a result of the Slice Settlement?*

A. Yes. The Slice Settlement contains a provision that addresses the treatment of bad debt related to direct service industries (DSIs). Specifically, allowances for uncollectible DSI liquidated damages for fiscal year 2002 or prior years will not be included in the Actual Slice Revenue Requirement or Slice True-Up Adjustment Charge. As a result, Slice customers will not receive any future credits for subsequent recovery of any receivables related to amounts previously written off that BPA collects from DSIs.

Q. *Are there any other changes due to the Slice Settlement?*

A. Yes. The treatment of Slice Computer Application Project costs changed as a result of the Slice Settlement.

Q. *How did the treatment of Slice Computer Application Project costs change?*

A. Consistent with BPA's Software Capitalization Policy or Personal Property Capitalization Policy, any hardware or software acquired for the Slice Computer Application Project and for implementing the Block and Slice Power Sales Agreement (Block/Slice PSA) will be capitalized over the shorter of a five-year period or the remainder of the Block/Slice PSA term, which ends on September 30, 2011. This represents a change from what was determined in the WP-07 Final Proposal where all

Slice Computer Application Project costs were treated as current expenses, rather than capitalized and recovered over a five-year period.

Section 4: Residential Exchange Program Expenses

Q. What REP expenses are included in the Slice Revenue Requirement for FY 2009?

A. As the result of the previously referenced decisions by the Ninth Circuit, the Slice Revenue Requirement for FY 2009 no longer includes an expense related to the REP settlements. Instead, the Slice Revenue Requirement will incorporate the expenses related to the REP net benefits that have been determined in this proceeding. The net expense for the REP benefits is forecast to be $202.252 million in FY 2009.

Q. What was BPA's forecast for this expense for FY 2009?

A. Previously, the payments under the REP settlements were estimated to be $300 million, specified under the IOU contracts or contract amendments entitled, "Agreement Regarding Payment of Residential Exchange Program Settlement Benefits during FY 2007-2011." This total includes $1 million to account for the interest on the balance of the FY 2003 $55 million payment deferral for all IOUs not repaid as of September 30, 2006. These expenses are no longer part of the Slice Revenue Requirement for FY 2009.

Q. Are there other expenses related to the REP settlements that had been included in the previous Slice Revenue Requirement for FY 2009?

A. BPA also included a line item in the Slice Revenue Requirement for "deferred augmentation expenses" related to those augmentation expenses incurred during the FY 2002-2006 rate period, but the payment of which is deferred to the FY 2007-2011 period. The "deferred" augmentation expenses were associated with payment of a "Reduction of Risk Discount" to Puget Sound Energy and PacifiCorp. With interest payments, this resulted in $115 million of deferred augmentation expenses for FY 2007-

2011, and was to be recovered through Priority Firm (PF) rates in amounts of approximately $23 million per year. In the WP-07 Final Studies, the Administrator confirmed that these costs were augmentation costs that would have otherwise been paid by Slice and non-Slice customers through the Load-Based Cost Recover Adjustment Clause (LB CRAC) and these costs were appropriate to include in the Slice Revenue Requirement in order to avoid any cost shift between Slice and non-Slice customers. As a result of the fact that the Court set aside the underlying agreements related to these payment, BPA's forecast of this expense is now zero for FY 2009.

Q. Will the expenses related to the REP benefits be subject to the Slice True-Up for FY 2009?

A. Yes. The expenses related to the REP net benefits will be subject to the Slice True-Up for FY 2009.

Section 5: Methodology to Calculate Slice Rate and Slice True-Up Adjustment

Q. Is BPA proposing to update the Methodology to Calculate the Slice Rate and Slice True-Up Adjustment (Slice Rate Methodology) in the WP-07 Supplemental proceeding?

A. Yes. BPA is proposing to make several minor updates to the Slice Rate Methodology to avoid confusion during FY 2009. These updates are intended to account for changes in circumstances since the Slice Rate Methodology was initially established and are not intended to materially change the Slice Rate Methodology.

Q. Please identify the proposed updates.

A. The proposed updates include changes that make the Slice Rate Methodology consistent with the provisions of the Slice Settlement Agreement. The Slice Rate Methodology included in the 2007 Supplemental General Rate Schedule Provisions, WP-07-E-BPA-51. A redline version showing edits that indicate the areas of change is available.

Q. Does this conclude your testimony?

A. Yes.

Table 1, Slice Product Costing and True-Up Table

	SLICE PRODUCT COSTING AND TRUE-UP TABLE ($000s)	Audited Actual Data	FY 2007 forecast	FY 2008 forecast	FY 2009 forecast
1	**Operating Expenses**				
2	**Power System Generation Resources**				
3	**Operating Generation**				
4	COLUMBIA GENERATING STATION (WNP-2)		$ 263,669	$ 188,688	$ 274,342
5	BUREAU OF RECLAMATION		$ 71,654	$ 74,760	$ 77,766
6	CORPS OF ENGINEERS		$ 161,519	$ 165,742	$ 170,407
7	LONG-TERM CONTRACT GENERATING PROJECTS		$ 24,932	$ 25,314	$ 31,864
8	**Sub-Total**		**$ 521,774**	**$ 454,504**	**$ 554,379**
9	**Operating Generation Settlement Payment**				
10	COLVILLE GENERATION SETTLEMENT		$ 16,968	$ 17,354	$ 17,749
11	SPOKANE GENERATION SETTLEMENT		$ -	$ -	$ -
12	**Sub-Total**		**$ 16,968**	**$ 17,354**	**$ 17,749**
13	**Non-Operating Generation**				
14	TROJAN DECOMISSIONING		$ 5,400	$ 4,700	$ 3,100
15	WNP-1&3 DECOMISSIONING		$ 200	$ 200	$ 200
16	**Sub-Total**		**$ 5,600**	**$ 4,900**	**$ 3,300**
17	**Contracted Power Purchases**				
18	PNCA HEADWATER BENEFIT		$ 1,714	$ 1,714	$ 1,714
19	HEDGING/MITIGATION (omit except for those assoc. with inventory solution)				
20	DSI MONETIZED POWER SALE		$ 59,000	$ 59,000	$ 54,999
21	OTHER POWER PURCHASES (short term - omit)				
22	**Sub-Total**		**$ 60,714**	**$ 60,714**	**$ 56,713**
23	**Augmentation Power Purchases**				
24	AUGMENTATION POWER PURCHASES (omit - calculated below)				
25	CONSERVATION AUGMENTATION (omit)				
26	PUBLIC RESIDENTIAL EXCHANGE (net costs)		**$ 6,762**	**$ 6,811**	**$ 9,391**
27	IOU RESIDENTIAL EXCHANGE		**$ 301,000**	**$ 301,000**	**$ 202,252**
28	**Renewable Generation (expenses related to reinvestment removed)**		**$ 30,289**	**$ 34,719**	**$ 50,379**
29	**Generation Conservation**				
30	LOW INCOME WEATHERIZATION & TRIBAL		$ 5,000	$ 5,000	$ 5,000
31	ENERGY EFFICIENCY DEVELOPMENT		$ 12,885	$ 12,908	$ 22,000
32	ENERGY WEB		$ 1,000	$ 1,000	$ 1,000
33	**LEGACY (Until 11/1/03 this was included with line 72)**		$ 3,728	$ 2,638	$ 2,114
34	MARKET TRANSFORMATION		$ 10,000	$ 10,000	$ 10,000
35	TECHNOLOGY LEADERSHIP		$ 1,300	$ 1,300	$ 1,300
36	INFRASTRUCTURE SUPPORT AND EVALUATION		$ 1,000	$ 1,000	$ 1,000
37	BI-LATERAL CONTRACT ACTIVITY		$ 1,000	$ 1,000	$ 1,000
38	**Sub-Total**		**$ 35,913**	**$ 34,846**	**$ 43,414**
39	CONSERVATION RATE CREDIT		$ 36,000	$ 36,000	$ 36,000
40	**Power System Generation Sub-Total**		**$ 1,015,019**	**$ 950,848**	**$ 973,577**
41					
42	**PBL Transmission Acquisition and Ancillary Services**				
43	**PBL Transmission Acquisition and Ancillary Services**				
44	PBL - TRANSMISSION & ANCILLARY SERVICES				
45	Canadian Entitlement Agreement Transmission Expenses		$ 24,806	$ 25,550	$ 26,991
46	PNCA & NTS Transmission and System Obligaton Expenses		$ 1,775	$ 1,825	$ 1,875
47	3RD PARTY GTA WHEELING		$ 47,000	$ 47,000	$ 48,000
48	PBL - 3RD PARTY TRANS & ANCILLARY SVCS				
49	RESERVE & OTHER SERVICES		$ 8,462	$ 8,462	$ 8,462
50	TELEMETERING/EQUIP REPLACEMT		$ 200	$ 200	$ 200
51	**PBL Trans Acquisition and Ancillary Services Sub-Total**		**$ 82,243**	**$ 83,037**	**$ 85,528**
52					
53	**Power Non-Generation Operations**				
54	**PBL System Operations**				
55	EFFICIENCIES PROGRAM (omit TMS expenses)		$ -	$ -	
56	INFORMATION TECHNOLOGY		$ -	$ -	$ -
57	GENERATION PROJECT COORDINATION		$ 5,637	$ 5,738	$ 5,844
58	SLICE IMPLEMENTATION (omit - calculated separately)				
59	**Sub-Total**		**$ 5,637**	**$ 5,738**	**$ 5,844**
60	**PBL Scheduling**				
61	OPERATIONS SCHEDULING		$ 8,758	$ 9,051	$ 9,353
62	OPERATIONS PLANNING		$ 5,202	$ 5,358	$ 5,521
63	**Sub-Total**		**$ 13,960**	**$ 14,409**	**$ 14,874**
64	**PBL Marketing and Business Support**				
65	SALES & SUPPORT		$ 15,884	$ 16,278	$ 16,745
66	Contractual exclusion		$ (5,360)	$ (5,360)	$ (5,360)
67	Implementation Expense Exclusions - Add back				
68	PUBLIC COMMUNICATION & TRIBAL LIAISON				
69	STRATEGY, FINANCE & RISK MGMT		$ 10,965	$ 11,359	$ 11,771
70	EXECUTIVE AND ADMINISTRATIVE SERVICES		$ 845	$ 840	$ 834
71	CONSERVATION SUPPORT (EE staff costs)		$ 6,441	$ 6,692	$ 6,953
72	**Sub-Total**		**$ 28,776**	**$ 29,808**	**$ 30,943**
73	**Power Non-Generation Operations Sub-Total**		**$ 48,372**	**$ 49,955**	**$ 51,662**
74					
75	**Fish and Wildlife/USF&W/Planning Council**				
76	**BPA Fish and Wildlife (includes F&W Shared Services)**				
77	FISH & WILDLIFE		$ 143,000	$ 143,000	$ 143,000
78	F&W HIGH PRIORITY ACTION PROJECTS				
79	**Sub-Total**		**$ 143,000**	**$ 143,000**	**$ 143,000**
80	**PBL-USF&W Lower Snake Hatcheries**				
81	USF&W LOWER SNAKE HATCHERIES		$ 18,600	$ 19,500	$ 20,400
82	**PBL - Planning Council**				
83	PLANNING COUNCIL		$ 9,085	$ 9,276	$ 9,467
84	**PBL - ENVIRONMENTAL REQUIREMENTS**				
85	ENVIRONMENTAL REQUIREMENTS		$ 500	$ 500	$ 500
86	**Fish and Wildlife/USF&W/Planning Council Sub-Total**		**$ 171,185**	**$ 172,276**	**$ 173,367**

Table 1, continued, Slice Product Costing and True-Up Table

87					
88	**BPA Internal Support**				
89	**CSRS/FERS**				
90	ADDITIONAL POST-RETIREMENT CONTRIBUTION	$ 10,550	$ 9,000	$ 15,375	
91	**Corporate Support - G&A (excludes direct project support)**				
92	CORPORATE G&A	$ 50,247	$ 51,753	$ 51,764	
93	**TBL Supply Chain - Shared Services**	$ 368	$ 374	$ 380	
94	**General and Administrative/Shared Services Sub-Total**	**$ 61,165**	**$ 61,127**	**$ 67,519**	
95					
96	**Bad Debt Expense**				
97	**Other Income, Expenses, Adjustments**	**$ 1,800**	**$ 1,800**	**$ -**	
98	**Non-Federal Debt Service**				
99	**Energy Northwest Debt Service**				
100	COLUMBIA GENERATING STATION DEBT SVC	$ 195,690	$ 217,856	$ 220,486	
101	WNP-1 DEBT SVC	$ 147,941	$ 165,916	$ 162,665	
102	WNP-3 DEBT SVC	$ 151,724	$ 160,092	$ 153,245	
103	EN RETIRED DEBT				
104	EN LIBOR INTEREST RATE SWAP				
105	**Sub-Total**	**$ 495,355**	**$ 543,864**	**$ 536,396**	
106	**Non-Energy Northwest Debt Service**				
107	TROJAN DEBT SVC	$ 8,605	$ 7,888	$ -	
108	CONSERVATION DEBT SVC	$ 5,203	$ 5,198	$ 5,188	
109	COWLITZ FALLS DEBT SVC	$ 11,619	$ 11,583	$ 11,571	
110	WASCO DEBT SVC	$ -	$ 1,664	$ 2,168	
111	**Sub-Total**	**$ 25,427**	**$ 26,333**	**$ 18,927**	
112	**Non-Federal Debt Service Sub-Total**				
113	Depreciation (excl. TMS)	$ 118,058	$ 121,829	$ 117,146	
114	Amortization (excludes ConAug amortization)	$ 55,567	$ 60,241	$ 59,745	
115	**Total Operating Expenses**	**$ 2,074,191**	**$ 2,071,310**	**$ 2,083,866**	
116					
117	**Other Expenses**				
118	Net Interest Expense	$ 163,080	$ 173,193	$ 155,981	
119	LDD	$ 22,289	$ 22,612	$ 25,219	
120	Irrigation Rate Mitigation Costs	$ 10,000	$ 10,000	$ 12,000	
121	**Sub-Total**	**$ 195,369**	**$ 205,805**	**$ 193,200**	
122	**Total Expenses**	**$ 2,269,560**	**$ 2,277,115**	**$ 2,277,066**	
123					
124	**Revenue Credits**				
125	Ancillary and Reserve Service Revs. Total	$ 73,131	$ 61,970	$ 74,213	
126	Downstream Benefits and Pumping Power	$ 8,921	$ 8,921	$ 8,921	
127	4(h)(10)(c)	$ 84,707	$ 84,927	$ 84,581	
128	Colville and Spokane Settlements	$ 4,600	$ 4,600	$ 4,600	
129	FCCF				
130	Energy Efficiency Revenues	$ 12,885	$ 12,908	$ 22,000	
131	Miscellaneous	$ 3,420	$ 3,420	$ 3,420	
132	**Total Revenue Credits**	**$ 187,664**	**$ 176,746**	**$ 197,735**	
133					
134	**Augmentation Costs**				
135	**IOU Reduction of Risk Discount (includes interest)**	$ 23,024	$ 23,024		
136	(Net augmentation power costs are not subject to True-Up)				
137	**Forecasted Gross Augmentation Costs**				
138	Residual augmentation cost	$ 49,005			
139	Other augmentation cost	$ 97,062	$ 95,001	$ 186,827	
140	Minus revenues	$ 67,993	$ 42,972	$ 81,092	
141	**Net Cost of Augmentation**	**$ 101,098**	**$ 75,053**	**$ 105,735**	
142					
143					
144	**Minimum Required Net Revenue calculation**				
145	Principal Payment of Fed Debt for Power	$ 202,331	$ 172,483	$ 103,065	
146	Irrigation assistance	$ -	$ 2,950	$ 7,279	
147	Depreciation	$ 118,058	$ 121,829	$ 117,146	
148	Amortization	$ 71,658	$ 76,332	$ 73,080	
149	Capitalization Adjustment	$ (45,937)	$ (45,937)	$ (45,937)	
150	Bond Premium Amortization	$ 613	$ 613	$ 185	
151	Principal Payment of Fed Debt exceeds non cash expenses	$ 57,939	$ 22,596	$ (34,130)	
152	Minimum Required Net Revenues	**$ 57,939**	**$ 22,596**	$ -	
153					**3-Year Total Rev Reqt**
154	Annual Slice Revenue Requirement (Amounts for each FY)	**$ 2,240,934**	**$ 2,198,018**	**$ 2,185,066**	**$ 6,624,018**
155					
156	SLICE TRUE-UP ADJUSTMENT CALCULATION				
157	FY 2007-2009 Average Slice Revenue Requirement determined in WP-07 Rate Case	**$ 2,252,465**			
158	FY 2007-2009 Average Slice Revenue Requirement determined in WP-07 Supplemental Rate Cas	**$ 2,208,006**			
159	TRUE UP AMOUNT (Diff. between actual Slice Rev Reqt and forecast average Slice Rev Reqt)				
160	AMOUNT BILLED (22.6278 percent)				
161	Slice Implementation Expenses (not incl. in base rate)				
162	TRUE UP ADJUSTMENT				
163					
164					
165	**SLICE RATE CALCULATION ($)**				
166	**Monthly Slice Revenue Requirement (3-Year total divided by 36 months)**				**$ 184,000,500**
167	**One Percent of Monthly Requirement (Slice Rate per percent Slice - Monthly Slice Rev. Req't. divided by 100)**				**$ 1,840,005**
168					
169	**ANNUAL BASE SLICE REVENUES**				**$ 499,623,182**
170	**Annual Slice Implementation Expenses**				**$ 2,400,000**
171	**TOTAL ANNUAL SLICE REVENUES**				**$ 502,023,182**

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TESTIMONY of

JANET ROSS KLIPPSTEIN, GERALD C. BOLDEN, and RONALD J. HOMENICK

Witnesses for Bonneville Power Administration

SUBJECT: SUPPLEMENTAL GENERATION INPUTS FOR ANCILLARY SERVICES

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TESTIMONY of

JANET ROSS KLIPPSTEIN, GERALD C. BOLDEN, and RONALD J. HOMENICK

Witnesses for Bonneville Power Administration

SUBJECT: SUPPLEMENTAL GENERATION INPUTS FOR ANCILLARY SERVICES

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Janet Ross Klippstein. My qualifications are contained in WP-07-Q-BPA-25.

A. My name is Gerald (Gery) C. Bolden. My qualifications are contained in WP-07-Q-BPA-05.

A. My name is Ronald J. Homenick. My qualifications are contained in WP-07-Q-BPA-17.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to explain the updates to generation inputs for ancillary services for FY 2009 based on updated revenue forecast data. This testimony also sponsors Section 4 of the 2007 Supplemental Wholesale Power Rate Development Study (WPRDS), WP-07-E-BPA-49, and Table 4.4 in the WPRDS Documentation, WP-07-E-BPA-49A.

Q. How is your testimony organized?

A. Our testimony is organized first by describing updates from the WP-07 Final Proposal to the forecasts of Generation Supplied Reactive and Voltage Control and to Operating Reserves – Spinning and Supplemental. Then we explain the other changes that we expect will result from the Wind Integration Rate Case.

Section 2: Changes to the Generation Inputs for FY 2009

Q. What has changed for generation inputs between the WP-07 Final Proposal and this Supplemental Proposal?

A. Changes have occurred in two generation inputs for ancillary services between the WP-07 Final Proposal and this Supplemental Proposal. The two generation inputs are Generation Supplied Reactive and Voltage Control and Operating Reserve – Spinning and Supplemental.

Q. What is the reason for the update to the forecast for generation supplied reactive?

A. As part of the WP-07 rate proceeding, BPA's Power Services submitted a supplemental proposal on Reactive Power. *See* Bermejo, *et al.*, WP-07-E-BPA-28; Supplemental Study – Reactive Power, WP-07-E-BPA-29. The supplemental proposal changed the costs to Transmission Services for Generation Supplied Reactive (GSR) by eliminating compensation for within the band payments made by Transmission Services to Power Services. This adjustment was dependant on Transmission Services being able to prevail in a Federal Power Act section 206 filing (16 U.S.C. § 824e) at the Federal Energy Regulatory Commission (FERC) to eliminate within the band payment to non-federal generators.

Q. What impact does this change have on BPA's generation input revenue forecast?

A. Because the outcome of this section 206 action was unknown when the WP-07 case was completed, BPA forecast $12.5 million in revenue to account for this uncertainty. Subsequently, FERC rendered a decision that eliminated the non-federal generator rate for inside the band GSR. Although this decision is currently subject to rehearing at FERC, Power Services is no longer receiving revenue for inside the band GSR. Therefore the revenue forecast for FY 2009 for GSR has changed from $12.5 million to $4.091 million, which is the synchronous condensing costs associated with plant modification and energy consumed. Synchronous condensing is neither an inside or outside the band operation. The FY 2009 revenue from Transmission Services for synchronous condensers is set in a Memorandum of Agreement between the business lines at $4,091,096 per year.

Q. What is the basis for the change for operating reserves?

A. The operating reserves forecast increased by 87 MW for FY 2009 to a total of 467 MW. The 87 MW change was the result of an increase in Total BPA Control Area Reserve Obligation and a decrease in Self-Supply and Third-Party Supply Reserve Obligation. The updated forecast is based on the actual FY 2008 operating reserve requirement notification from Transmission Services to Power Services in June 2007 per the inter-business line Memorandum of Agreement. The per-unit price remains $5.63 per kilowatt-month for FY 2009 based on the Partial Resolution of Issues.

Q. What impact does this change have on BPA's generation input revenue forecast?

A. The revenue forecast increased $5.878 million for FY 2009.

Q. Are there any other changes to generation inputs that will affect forecasted revenues?

A. Power Services will provide to Transmission Services generation inputs for within-hour balancing service for wind integration. The amount of generation inputs required for FY 2009 and the per-unit price between Power Services and Transmission Services are decisions to be determined in the Wind Integration rate proceeding (WI-09). That rate case will be going on concurrently with the Supplemental Proposal. We have included an estimate of the revenues to be received from Transmission Services for providing the generation inputs based on the wind integration rate case initial proposal. The initial proposal forecasts Power Services providing an annual average of 203 MW of within-hour balancing capability. As a conservative estimate of the revenue to be received from this service, we are using the regulation embedded cost portion of the product determined in the WP-07 Final Proposal for the forecast. The embedded cost portion of the regulation price is $5.76 per kW-month. The forecasted revenue from this service is $14.031 million.

Q. Are you addressing the methodology or pricing for the within-hour balancing service for wind integration in this rate proceeding?

A. No. The methodology and pricing for the within-hour balancing service for wind integration are being addressed only in the Wind Integration rate proceeding.

Q. How do you plan to account for the changes that may be proposed in the wind rate case?

A. "Within-hour balancing service" is the new generation input for the ancillary service Transmission Services will provide to wind generators in the BPA Control Area in FY 2009. The forecast will be updated for the final Supplemental Proposal with the most current information from the Wind Integration Rate Case studies in both per-unit price and forecasted within-hour balancing service needed. The forecast revenue Power Services will receive for this new service will be added to the generation inputs for ancillary services revenue forecast.

Q. What is the net effect of these changes on revenue received for generation inputs?

A. The net effect of these three changes for FY 2009 is $11.497 million additional revenue than previously forecast in the WP-07 Final Proposal.

Q. Why are you not addressing the other generation input forecasts, and why are you not discussing the underlying methodologies used to determine these cost allocations?

A. We are not addressing the other forecasts of generation inputs for ancillary services because there have not been changes in the amount nor per-unit price of the services identified in the WP-07 Final Proposal. In addition, Transmission Services has established its transmission and ancillary services rates for FY 2008 and FY 2009. Nothing in this Supplemental Proposal will affect the revenue forecasts for the other generation inputs, and those forecasts of revenue are still the best information we have at this time. The underlying methodologies for all the generation inputs for ancillary services are explained in the testimony, studies and documentation for the WP-07 Final Proposal.

Q. *Does this conclude your testimony?*

A. Yes.

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